



**FINAL REPORT AND STATEGIC PLAN
ON
THE FEASIBILITY STUDY TO ASSESS GEOTHERMAL POTENTIAL
ON
WARM SPRINGS RESERVATION TRIBAL LANDS**

REPORT NO: DOE/GO/15177

**SUBMITTED BY
WARM SPRINGS POWER & WATER ENTERPRISES
A CORPORATE ENTITY
OF
THE CONFEDERATED TRIBES OF WARM SPRINGS
WARM SPRINGS, OREGON**

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Executive Summary

Commercial use of geothermal energy for power development requires a geothermal resource reservoir capable of providing high temperature hydrothermal fluids. Geothermal reservoirs are generally classified as being either low temperature (<150° C) or high temperature (>150° C). Generally speaking, the high temperature reservoirs are the ones suitable for, and sought out for commercial production of electricity. Geothermal reservoirs are found in “geothermal systems” which are regionally localized geologic settings where the earth’s naturally occurring heat flow is near enough to the earth’s surface to bring steam or hot water to the surface. Geothermal systems are often found associated with young volcanic areas. Developed geothermal systems can be found throughout the world in the volcanic regions of New Zealand, Japan, Indonesia, Iceland, and the United States. In the United States developed geothermal systems include the Geysers Region in Northern California, the Imperial Valley in Southern California, the Coso Volcanic Field in Inyo County California, Mammoth Crater in eastern California and numerous locations throughout Nevada and Utah.

The geothermal resource exploration area on the Warm Springs Reservation is located on the eastern slope of Mt. Jefferson. Mt. Jefferson is a large stratovolcano the U.S. Geological Survey has classified as a site with significant potential for geothermal resources. In 1991 the Warm Springs Tribal Council authorized a geological assessment of this area by a private exploration company, California Energy Company. This early exploration work was completed at no cost to the Tribes. This initial study identified an area with significant geological potential for geothermal resources. Exploration drilling was not initiated at that time due to the combination of market conditions and tribal interest not being sufficient or favorable to warrant exploration or further discussions regarding a development agreement. Market conditions have improved significantly since 1991.

In 2005 Warm Springs Power and Water Enterprises obtained a grant from the U.S. Department of Energy to fund a new geothermal resource assessment feasibility study and to identify options for the Confederated Tribes of Warm Springs regarding possible development of a geothermal power plant. The resource assessment work was completed in 2006 by GeothermEx Inc., a consulting company specializing in geothermal resource assessments worldwide. GeothermEx is one of the most qualified independent geothermal resource assessment firms used by banks and government agencies throughout the world for independent assessment of geothermal resource potential.

The identified exploration area has extensive young volcanism dominated by domes and lava flow magmas with greater than 60% silica content. The area also has several areas of hydrothermal alteration and hydrothermal mineralized springs. The volcanic activity of the Mt. Jefferson volcanic highlands is similar in intensity to those found in Wairakei, New Zealand, several Indonesian and Philippines geothermal fields and the Coso and Steam Boat geothermal areas of the United States. The young age and the chemistry of volcanic outcrops in the Mt. Jefferson area of the Reservation create a relatively high probability that one or more shallow magma chambers are present in this area which would generate sufficient heat flow to create a geothermal reservoir. Geochemical analysis of the hydrothermal springs in Shitike Creek completed by GeothermEx and the US Geological Survey suggest that deep underground water temperatures could be in the range of 150° to 200°C (302° to 392°F) with a most likely value of 175°C (347°F). Reservoir temperatures of 144°C are considered to be sufficient to develop power generation.

The GeothermEx study completed a Monte Carlo simulation of the volumetric heat in place in the study area to estimate the potential size of the resource. The Monte Carlo simulation models used by GeothermEx are relied upon by major banking institutions and governments' world wide to evaluate geothermal resource potential. The Monte Carlo simulation of the exploration area suggests that a geothermal resource reserve capable of supporting a 20 MW power plant has a 90% confidence level. The Monte Carlo model also estimates that the most likely value of reserves is 37 MW and the median value is 50 MW. The study used a base-case of a 30-MW (net) project for the initial development scenario.

The geothermal project has been divided into three major phases which may take several years to complete and each phase has different degrees of cost and financial risk:

- Initial Exploration Drilling Phase,
- Confirmation Drilling and Reservoir Testing Phase and
- Development Phases.

The highest risk phases of the project are the Exploration and Confirmation drilling programs. The study also established as governing criteria that all development would be confined to the ridge areas between Shitike Creek and Whitewater Canyon and that development would not occur on the floor of these large valleys. Drilling costs in all three phases are significantly affected by the approach of confining well field development to ridge areas between glaciated valleys. This approach adds about 400 meters (1,300 feet) to the depth required to reach a given elevation within the geothermal reservoir. The topography of the ridge areas also has a significant impact on costs and on the likely distribution of surface facilities. An area south of Shitike Creek canyon was identified as the primary target area that would be relatively favorable for development from a topographic point of view, assuming that the area is also within drillable distance of a geothermal reservoir. The initial exploration drilling program has been located in this topographically favorable area.

Exploration drilling is expensive and has high risk. The Tribes' ability to advance to the next step is difficult given the current economic condition. Warm Springs Power & Water Enterprises recommends a prudent plan of exploration involving a multi-year drilling program to confirm and quantify the geothermal resource production potential. Warm Springs Power & Water Enterprises also recommends that the Tribes take maximum advantage of federal programs to assist in the development of renewable energy resources to reduce the cost and risk of the initial exploration.

The first phase of the exploration program will involve drilling several deep exploration wells called slim wells. These small diameter wells will be drilled to over 6,000 feet deep and will test the area for rock temperatures, geological data and the presence of high temperature thermal fluids. This initial exploration program will be combined with a geophysical survey that will cover a much larger area from the southern boundary of the Reservation to Shitike Creek. The geophysical surveys consist of a resistivity-based survey to look for alteration associated with hydrothermal fluids, plus a gravity survey to look for differences in formation density that could provide insight into reservoir structure. The area of coverage for both surveys should be approximately 23 square miles, covering an N-S elongated area 2.5 miles wide and 9 miles long.

The estimated cost of the first phase of the exploration program is \$3.651 million. This is the highest risk phase of the project. To minimize this risk and to develop more information on the geothermal resource potential, Warm Springs Power & Water Enterprises has applied to the Bureau of Indian Affairs for a grant to complete this initial exploration phase.

The \$3.651 million initial exploration cost represents the project's exposure to "Exploration Risk" up to the first Go / No-Go point for the multi year exploration program. If the initial drilling program indicates favorable conditions for further exploration, the exploration program would extend to a second phase, involving an additional cost of about \$3 million to drill the initial confirmation exploration wells in the area to further define the reservoir area. Warm Springs Power & Water Enterprises recommends that the Tribes also seek federal grants for drilling the additional confirmation production test wells in the exploration area to help it reach the second Go /No-Go decision point.

More than one well will be needed to complete the reservoir testing program. The costs for the confirmation drilling and reservoir testing phase are estimated at about \$16.065 million which would include \$14 million for 4 full-sized production test wells at \$3.5 million apiece. Prior to committing to additional drilling, the Tribes should consider a development partner to share the confirmation drilling and testing risk and financial risk of full development.

These wells are assumed to be 2,500 meters (8,200 feet) deep to ensure adequate penetration of the reservoir. This phase also assumes that at a minimum two wells are successful and can be tested to confirm the reservoir's productivity. Also an additional \$1.5 million would be spent on environmental studies and associated reporting and administrative costs. The reservoir testing program has to have sufficient positive results to support project financing in order for the Tribes to go forward with full development.

Costs for the Development phase (from closure of financing to plant start-up) are estimated at about \$117.7 million. This includes \$42 million for an additional 12 full sized holes to achieve a total of 7 producing wells with an average capacity of 5 net MW each and 7 injection wells; and an estimated cost of \$67.6 million for the power plant and gathering system.

A new, 15-mile transmission line to connect to the hydro-project 230-kV line has been estimated at \$4 million, using a representative cost of \$267,000/mile.

Operations and maintenance costs have been assumed to be \$5.256 million per year, equivalent to 2¢/kWh for an output of 30 MW net.

The base case economic assumptions for the cash-flow analysis used an electricity price assumption of 7.5¢/kWh with an 8% construction interest and 2% inflation rate. The economic analysis indicates that the Tribes would have to obtain an electricity price above 7.5¢/kWh for the project to have a positive pay-out over a 30 year life and electricity price of 7.2¢/kWh just to break even. The economics of the project improve dramatically if the electricity price is greater than 8.0¢/kWh and would have a significant positive impact if the Tribes could arrange for use of a production tax credit (PTC).

Since the Confederated Tribes of Warm Springs pay no income tax, the PTC would not be available to them directly. However, it might be available to an outside entity that was contracted to build, own and operate the geothermal plant, assuming that the outside entity had a tax liability it could offset with the PTC from its Warm Springs operations.

An increase of 1.9¢ in the effective price per kWh for the first 10 years of the project life would result in a present value of \$19 million for the base-case assumption of a pre-PTC price of 7.5¢/kWh. With the PTC benefit, the project would break even at a pre-PTC price as low as 6.2¢/kWh. For the Warm Springs base case with no PTC benefit, a discount rate of 13.5%

resulted in a present value of zero. For the case with a PTC benefit, the present value remained positive at discount rates above 20%.

In summary, the discounted cash-flow analysis based on realistic estimates of Capital and operations and maintenance costs suggests that the economics for a 30-MW project at Warm Springs are marginal for electricity prices under 7.5¢/kWh or for a project without the use of the PTC. If the project can obtain a price in excess of 8.5¢/kWh or a PTC partner, the project economics improve dramatically. It should be pointed out, however, that the estimates of reserves available and the numbers of wells required to develop these reserves are **very preliminary** and could be significantly changed by information from a few exploration wells.

Introduction

“At the time of creation the Creator placed us in the land and gave us the voice of the land and that is our law. Ultimate sovereignty is vested in the people, who received their sovereign authority in the form of laws given by the creator and by the land itself. We shall, as we always have, live in balance with the land and never use more of our precious natural resources than can be sustained forever.” (From The Warm Springs Declaration of Sovereignty.)

The Warm Springs Integrated Resource Management Plan was derived from these long-standing beliefs. The Warm Springs tribal leadership reflects these values, beliefs, teachings and practices that have been handed down from several hundred generations who relied on the resources from this land. Integrated management combines an understanding of tribal values with the knowledge to assess natural resources. The Tribes and the government of the United States retain a sacred treaty trust and a public trust obligation to support tribal management of natural resources. This public trust must strike a balance between the environmental responsibility and the need for sustainable economy and a sustainable culture. The development of natural resources such as geothermal resources from tribal lands must be based on these core principles and values.

Since the early 1980's the U.S. Geological Survey (Circular 790) and geothermal industry interests have recognized the Mt. Jefferson area to be an area with significant potential for geothermal resources. In 1991 Warm Springs Power and Water Enterprises collaborated with a private exploration company, California Energy Company, to conduct a reconnaissance exploration of this area. This initial study identified an area with significant geological potential for geothermal resources. A contractual agreement for exploration drilling was not initiated at that time because the combination of market conditions and tribal interests were not sufficient or favorable to warrant exploration or a development agreement. Market conditions have improved significantly since 1991 and there is considerably greater interest in developing new power generation in the region using clean, sustainable renewable energy resource.

In 2005 the Tribal Council authorized a new evaluation of the geothermal development potential. Warm Springs Power & Water Enterprises obtained a grant from the U.S. Department of Energy to conduct a new geological assessment and development estimate. Warm Springs Power & Water Enterprises utilized a team of expert consultants to conduct the study and develop a strategic plan. The geothermal resource assessment and other cost, risk and constraints information has been incorporated into this strategic plan. See Attachment 1 for a copy of geological assessment by GeothermEx Inc. GeothermEx is one of the world's leading independent experts on geothermal resource development and is utilized by most of the major financial institutions to complete due diligence reviews of projects.

The GeothermEx report indicates there is a 90% probability that a commercial geothermal resource exists on tribal lands in the Mt. Jefferson area. This strategic plan recommends a prudent plan of exploration involving a multi-year drilling program to confirm and quantify the geothermal resource production potential. The first phase of the exploration program will involve the drilling of two deep exploration slim wells combined with a geophysical survey. The estimated cost of the first phase of the exploration program is \$3.6 million. This would be followed by a confirmation drilling phase that would cost approximately \$16.2 million. If exploration and confirmation drilling were successful the project would then move to the well field and power plant development phase which is estimated to cost \$97.1 million. The

preliminary cost and economic assessment concludes that the initial 30 MW (net) project would cost an estimated \$117 million which would include the energy supply for the power plant, the power plant cost and transmission improvements. The highest risk phases will be the exploration and confirmation drilling phases. The estimated project costs were based on very conservative assumptions regarding well cost and project development cost.

The strategic plan breaks down the project into a Resource Development Plan, a Power Plant Development Plan, a Transmission and Interconnection Plan and a Power Marketing Plan. The strategic plan also reviews economic risk and methods to reduce the Tribes' risk by identifying options for the Tribes to consider that could move the development forward while reducing the Tribes' financial risk and retain Tribal ownership and sovereignty.

Resource Development Plan

Project Area

A broad area of the Warm Springs Reservation has been identified as a potential geothermal resource area. The geothermal resource exploration area is located on the eastern slope of Mt. Jefferson, which is a large stratovolcano that has been identified by the U.S. Geological Survey and other researchers as an area with significant potential for geothermal resources. See Figure 1 for a map of the Warm Springs geothermal exploration area.

In 2005 the Tribal Council authorized an evaluation of the geothermal development potential. See Attachment 2 for a copy of GeothermEx report which documents the findings and describes the geological setting for the exploration program. The GeothermEx report recommends a prudent plan of exploration involving a multi-year drilling program to confirm and quantify the geothermal resource production potential. The identified exploration area has extensive young volcanism dominated by lava domes and flows from magma chambers with greater than 60% silica content. Magma chambers of this type generate significant heat flow to create geothermal reservoirs.

See Figure 2 for a map of the area on the Reservation that has been targeted for geothermal exploration. The exploration area also has several areas of hydrothermal alteration and hydrothermal mineralized springs with Na-K-Ca geochemical ratios that indicate a reservoir temperature in excess of 144°C, which is the resource temperature considered to be sufficient to develop power generation. The volcanic activity of the Mt. Jefferson volcanic highlands is similar in intensity to those found in Wairakei, New Zealand, several Indonesian and Philippines geothermal fields and the Coso and Steam Boat geothermal areas of the United States.

The geothermal project has been divided into three major phases. Each phase may take several years to complete and each phase has different degrees of cost and financial risk:

- Exploration Drilling Phase,
- Confirmation Drilling and Reservoir Testing Phase and
- Development Phase.

Each phase of development will require tribal environmental analysis. The project area has limited roads and new roads will be required to fully develop the project.

The study used a base-case of a 30-MW (net) project for the initial development scenario cost estimate. The primary assumptions for the project design and cost estimate are:

- 30 MW Net Output
- <190°C Reservoir Temperature
- Location will be on the ridgeline/plateau area between Shitike Creek and White Water Canyon

These basic assumptions dictate the project area logistical cost, the number of wells and the type of power plant technology that will be used in the cost estimate.

Resource Development Assumptions

The preliminary cost estimate for the geothermal project at Warm Springs is based on a series of assumptions regarding the resources which have a direct affect on power cycle and well completion cost. The following resource assumptions are made:

- Resource Depth: >8,000 feet
- Resource Temperature: 150 to 200 deg C (302 to 392 deg F)
- Well Production By Electric Submersible Pumps (ESP)
- Production Rates: Max Flow Rates 2,700 GPM; Average Flow Rate 2200 GPM
- Pump Setting Depth: 2,800 Feet,
- Equivalent Well Head Power Output: 5 net MW per well.

The young age and the chemistry of volcanic outcrops in the areas create a relatively high probability that one or more shallow magma chambers are present in this area which would generate sufficient heat flow to create a geothermal reservoir. The GeothermEx report presents a detailed geochemical analysis of hydrothermal waters found on the Reservation and on adjacent U.S. Forest Service lands. The geochemistry of these thermal seeps and springs indicates that these thermal waters are most likely derived from a common high temperature geothermal system in the Mt. Jefferson volcanic highlands where the Warm Springs geothermal project would be located. Geothermometry based on samples from the thermal seeps in the exploration area suggest that water temperatures in the range of 150 to 200 deg C (302 to 392 deg F) with a most likely value of 175 deg C (347 deg F). The geochemistry data is used as the base assumption regarding potential reservoir temperatures. This assumption will affect other design and cost assumption. The reservoir temperature assumption will also dictate that the project power cycle will be a binary power plant. Development of a geothermal power project within the Reservation near Mt. Jefferson will most likely be confined to the ridge areas between the east draining, glaciated valleys of Shitike Creek and the White Water River. Environmental constraints will prevent or significantly limit drilling and development within these river valleys. These ridge areas will most likely have deep water tables and production from deep geothermal wells in this area are assumed to likely entail the use of electric submersible pumps. The cost of well drilling and selection of a power plant cycle for the project cost estimate was based on these very conservative assumptions regarding the depth of the wells and the need for ESP to lift the thermal fluids to the power plant.

Exploration Drilling, Phase 1 Slim Hole Drilling

The highest risk phases of the project are the Exploration and Confirmation drilling programs. Because the study established as governing criteria that all initial exploration drilling would be confined to the ridge areas between Shitike Creek and Whitewater Canyon, the drilling costs are significantly affected. An exploration drilling approach that confines well field development to ridge areas between the glaciated valleys adds about 400 meters (1,300 feet) to the depth required to reach a given elevation within the geothermal reservoir. This will increase development cost.

The topography of the ridge areas also has a significant impact on costs and on the likely distribution of surface facilities. An area south of Shitike Creek canyon was identified as the primary target area that would be relatively favorable for development from a topographic point of view and appears to also be also within drillable distance of a geothermal reservoir. The initial exploration drilling program has been located in this topographically favorable area and cost of drilling is based on sites identified in Figure 3.

The plan of exploration involves a multi-year drilling program to confirm and quantify the geothermal resource production potential. The initial stage of the exploration program is designed to define the heat flow and resource conditions that may exist on tribal lands. The initial exploration drilling program involves drilling the first two exploration slim wells as part of a multi-year plan of exploration and development to confirm the estimates of geothermal reserves.

The initial exploration program involves a 24 month program of work to build roads, drill two to three deep exploration slim wells, sample and test the wells and complete a broader regional geophysical survey of the project area.

Drilling production-size holes for geothermal exploration puts a large expense at the beginning of the project, and thus requires a long period of debt service before those costs can be recaptured from power sales. If a reservoir can be adequately defined and proved by drilling smaller, cheaper slim-holes, larger exploration and reservoir confirmation test well drilling can be delayed until the resource location is more fully defined. This approach will lower the exploration risk.

Slim hole drilling allows more control of the well drilling program and allows for deeper exploration than traditional core hole wells. Slim holes will also allow for production of reservoir fluids and the testing of reservoir porosity through injection while core holes by regulation are prohibited from being flow tested. Exploration programs at other geothermal systems indicate that modeling correlations of fluid flow and injection tests between slim-holes and production size wells can provide significant information regarding resource productivity potential. The modeling of slim-hole exploration results as a reservoir assessment tool has become an accepted method for geothermal exploration. Well bore-reservoir flow simulator models have been used for reservoir evaluation from slim-hole flow data.

The first step in the exploratory drilling phase assumes the drilling of two deep slim hole test wells in the first two years of the development in the northern area of the exploration zone, adjacent to Shitike Creek. The purpose of these wells is to confirm the heat flow and to provide lithological information regarding subsurface formations and drilling conditions. See Figure 3 for a map of the proposed locations for six exploration sites to be tested with either temperature gradient wells or slim holes or a combination. The proposed program calls for the northern most exploration well sites to be drilled first with deep slim hole completion programs to test the resources area.

The slim hole drilling program would be combined with a geophysics survey of the exploration area to further identify the extent of resource anomaly zone and to further define the locations for additional exploration wells. The drilling of larger production test wells will depend upon successful results of the slim hole drilling program. The result may indicate that additional exploration sites should be drilling initially with Temperature Gradient Wells (TGH wells) if the slim hole drilling in the primary target area is successful. If the results are very favorable, the drilling of production sized wells would be considered. See Figure 4 for the locations of the two primary slim hole exploration wells.

The proposed slim hole exploration program will be completed over a 24 month period. The first year will be dedicated to construction of access roads and drilling of the deep slim holes. Because of the site access constraints and potential for weather constraints, a second year has been schedule to complete the geophysical surveys in the exploration area extending as far south as the southern boundary of the Reservation and to allow for follow up well logging and testing.

The exploration and development of the geothermal resource will be a multiyear program. The slim hole drilling program is just the initial and highest risk phase of the exploration program. An additional 3 to 4 production size confirmation wells and additional temperature gradient wells (TGH wells) will be needed to follow up on any indication of anomalous thermal gradients, thermal fluids and geophysical anomalies discovered by the initial exploration and geophysical surveys.

Initial Slim Hole Exploration Drilling Program Cost Estimate Assumptions:

- Minimum of two wells
 - Cost per well: \$1,300,000
 - Total Well Cost: \$2,600,000
- Geophysical Surveys: 23 sq. miles
 - CSAMT: \$250,000
 - Gravity: \$50,000
- Drilling Management and Consultants: \$150,000
- Environmental Assessment: \$50,000
- Road and Well Pad Construction \$80,000
- Tribal Management: \$58,800 (10% of non-drilling cost)
- 10% Contingency: \$323,880

Total slim hole and geophysics exploration drilling costs are estimated to be approximately \$3.6 million and will take two years to complete.

Exploration Drilling, Phase 2 Confirmation Well Drilling

Upon completion of the slim hole and geophysics exploration program and provided that this program has favorable results, the next phase of exploration drilling would be to drill large diameter production test wells to confirm the resource productivity. Confirmation well drilling would involve drilling a production size well to a depth of approximately 2,500 meters (8,200 feet). This depth has been assumed in order to ensure adequate penetration of the reservoir and to drill deep enough to reach a high temperature gradient.

The third No-Go decision point would require the first two confirmation wells to show negative results. A negative result would be that the wells are not hot enough to support a geothermal reservoir or the rock is not permeable enough to be productive and would not support development with either flash or binary technology.

The project's exposure to Confirmation risk up to the third No-Go point would be the cost of the slim hole drilling and additional cost of two dry holes, plus the incremental cost for completing the EIS and associated reporting and administrative costs. The sunk cost at the third No-Go point would be approximately \$8.5 million.

A successful confirmation drilling program would be that at least two of the four confirmation wells had favorable results. The costs for the confirmation drilling phase are estimated at about \$16.065 million, including \$14 million for 4 full-sized holes at \$3.5 million apiece. The drilling cost could be less if fewer than 4 wells are required to achieve the goal of 2 successful producers, or if total depths are less (either because reservoir permeability starts at higher elevations or because some accommodation is reached to allow drilling within the valleys).

The confirmation drilling program cost estimates were developed by GeothermEx and are based on current cost of drilling geothermal wells in Nevada and California. Drilling costs are subject to significant inflation and deflation depending upon the availability of drilling equipment. During periods of high oil and natural gas prices, exploration drilling in the oil and gas fields increases and the number of available large drill rigs decreases. This will drive up the daily rental rates for drilling equipment.

Confirmation Drilling Program Cost Estimates Assumptions:

- Two Temperature Gradient Wells (optional)
 - \$750,000 per well
 - Total TGH Cost \$1,500,000
- Four Production Test Wells
 - Full size wells
 - Depths to 2,500 meters (8,200 feet)
 - \$3,500,000 per well
 - Total Well Drilling Cost \$14,000,000
 - Assumes 1 dry well (not usable for any reason)
 - Assumes 1 well suitable for injection
 - Assumes 2 wells suitable for testing
- Roads and Well Pads
 - \$20,000 included in the well cost road and pad construction
 - \$80,000 Road and Well Cost
- Well Testing
 - Purchase of one electrical submersible pump (EMP) for pump testing
 - EMP Cost \$350,000
 - \$100,000 for other well testing and well logging cost
- Resource Reporting
 - Monitoring of drilling progress
 - Documentations for project financing reports
 - \$150,000
- Consultant Management, Reservoir Reports and Tribal Program Administration
 - 5% of well drilling, testing and reporting cost
 - \$765,000

Total confirmation exploration drilling costs are estimated to be approximately \$15,625,000 and will take two years to complete.

Completion of the resource confirmation drilling and testing program would bring the project to the third Go / No Go decision point. The successful testing of the confirmation wells will need to be documented for project finance reports. Well test data, regional geological data, and all data from the exploratory slim wells, and additional temperature gradient wells and the exploration confirmation wells will be used by the reservoir engineering consultants to prepare a reservoir assessment report for project financing. This report is used like an appraisal by the financial institutions and provides an independent and qualified appraisal of the resource that the power plant would rely on for energy supply.

Environmental Analysis

Each phase of the exploration program involves an extensive environmental analysis. The initial slim hole drilling and confirmation drilling programs involve temporary improvements. The roads and well pads could be reclaimed if the project is unsuccessful. The environmental analysis for each phase of exploration would be specific to the roads, well pad construction and operations of the exploration drilling equipment. The cost for the exploration environmental assessments is included in the exploration budgets. Full development of a permanent power plant and transmission line will involve a much more detailed NEPA analysis and involve a significantly higher cost.

An environmental analysis for the project's full development will be complete upon successful drilling and testing of the four production test wells, provided that the testing confirms the geothermal reservoir productivity will support a power plant development. NEPA compliance would be achieved either through the approval of an Environmental Assessment tiered from the Tribes' Intergraded Resource Management Plan Impact Statement or through a full Environmental Impact Statement (EIS). The cost assumption is that a full EIS would be prepared by the Department of Natural Resources through the use of a qualified contractor. The cost assumptions are based on a similar EIS prepared for the Telephone Flat 30 MW geothermal project located on US Forest Service lands. The cost for the Warm Springs EIS was factored from the US Forest Service EIS to obtain an order of magnitude estimate. The Warm Springs EIS estimate does not include the extensive public hearings, public outreach and scoping that is typical of the US Forest Service EIS process. The Warm Springs EIS cost estimate does include public scoping at the tribal level.

Approval of the Warm Springs Geothermal Project EIS is required for the project to proceed to the development stage. The approved EIS is also required by the financial institutions to obtain project financing.

Environmental Analysis Cost Estimate Assumptions:

- Tribal Scoping
 - Public Meetings
 - Field Visits
 - \$30,000
- Baseline Data Collection
 - Water Quality Studies: \$50,000
 - Biological Baseline: \$75,000
 - Cultural and other resources: \$25,000
 - Total Cost: \$150,000
- Completion of Environmental Impact Statement: \$380,000
- Tribal Administration: \$40,000

The environmental analysis cost for the geothermal project assumes the project completes a detailed environmental assessment which is estimated to cost approximately \$600,000. Environmental cost could go as high as \$1 million if the project scope was modified to allow for drilling the valley floors of Shitike Creek or Whitewater Canyon.

Go / No Go Decision Points

Development of the geothermal resources in the Mt. Jefferson area will involve significant exploration risk. The GeothermEx report recommends a prudent approach to exploring for this resource using a combination of slim wells and surface geophysics to better define the resource potential. Prior geological investigations suggest that the initial exploration should be in the northern area of the Mt. Jefferson volcanic area near Shitike Creek. The encouraging geothermometer temperatures from the Shitike Creek Seep indicate that this area may contain the best opportunity for discovery of a commercial resource. The initial exploration drilling program will also be combined with a series of geophysical surveys to be conducted over the entire prospective area, from the ridge north of Shitike Creek to the southern boundary of the reservation west of Bald Peter Butte.

Figure 5 illustrates a Go / No Go decision diagram for the exploration program.

If none of the initial slim holes are successful and if the geophysical results are discouraging in the north and the south, the project would have reached a No-Go point.

If the initial slim holes are discouraging, then the possibility of finding a productive area sufficiently large to be of commercial interest would be remote.

If the northern slim hole wells are all discouraging but the geophysical results suggest better potential to the south, a second exploration program should be considered to fully evaluate the southern area. If these southern sites are also discouraging, then the project would reach another No-Go point.

If at least one of the slim holes identifies a promising thermal gradient, then this result should be followed by the drilling of a pair of full-sized confirmation wells. Once the cost of mobilizing a rig to the area has been incurred, the incremental cost of a second well would probably be warranted, even if the first well was discouraging. The criterion of success for a full-sized confirmation well would be an indication of potentially commercial temperatures and flow rates. This would need to be demonstrated by a flow test, in all likelihood requiring the purchase of a down-hole pump specifically for this purpose.

If neither of the first two full-sized wells demonstrates commercial productivity, and if no means of improving the drilling strategy is identified, the project would be at another No-Go point, with the cumulative expenditure of exploration phase costs, plus the cost of the first two full-sized wells.

If at least one of the first pair of confirmation wells demonstrates commercial potential, then the project would reach a Go-point and the balance of confirmation drilling would follow. The criterion of success for the entire confirmation phase would be demonstration of flow rates and temperatures equivalent to at least 25% of the target plant size; for example, 7.5 net MW to justify proceeding with a plant capacity of 30 net MW (base case).

A Go decision point for full project development would require that the cumulative result of the drilling during the confirmation phase require three of the four full-sized wells to include at least two productive wells, with one well suitable for injection (at least for the duration of an extended pump test to evaluate the productive wells), and possibly a dry hole.

The successful accomplishment of the Confirmation phase of drilling and testing should provide the basis for a resource assessment report that can justify project financing.

The resource assessment report would also lay the technical groundwork for negotiations toward final power purchase agreement (PPA) terms and provide the technical basis for the detailed design, engineering, procurement and construct (EPC) contract for the Development phase of the project.

Exploration Program Schedule

At this point in the development program a realistic project schedule can not be projected. Typical development timeframes for geothermal projects on federal lands in the western United States have been between five and 10 years. Aggressive developments such as the Coso Geothermal Project which was built on US Navy and BLM lands resulted because the developer had a power sales contract with a high enough price to obtain project funding. Prior to obtaining a power sale agreement and private investment funding for this project, the developer, California

Energy Company had drilled several exploration wells to confirm the resource. In almost all cases of commercial power development of geothermal resources in the United States the projects had completed at least one confirmation well prior to obtaining a power sales agreement and project funding.

The GeothermEx report projected a five year development program based on an aggressive but logical succession of events. This schedule is based on the assumption that the Tribes would team with an experienced developer who would have a power purchase agreement in place. Figure 6 contains the projected development program by GeothermEx.

Warm Springs Power & Water Enterprises projects that a seven to ten year project schedule is more realistic given the delays that will be inherent in obtaining tribal funding for the exploration program and the market constraints that may affect the Tribes' ability to obtain an adequate power sales agreement with a regional utility for the wholesale purchase of the power.

Warm Springs Power & Water Enterprises projects that the initial slim hole exploration program and geophysical surveys will take a minimum of two years to complete the scope of work and evaluate the findings.

Figure 7 contains a modified timeline that include several schedule delays for the Tribal review and evaluation of the project risk and benefits prior to electing to proceed.

Financial Risk Associated With Exploration Drilling

Phase 1. Slim Hole Drilling Cost: The slim hole drilling program is the highest risk phase of the project. Slim hole drilling and geophysics exploration cost are estimated to be approximately \$3.6 million and will take two years to complete. Warm Springs Power & Water Enterprises has applied for a grant from the BIA to complete this phase of the exploration.

Phase 1. Confirmation Drilling Cost: The confirmation drilling would follow the slim hole drilling and should only be completed if the slim hole drilling has favorable results. The confirmation drilling has a "lower exploration risk" in that it builds upon the success of the slim hole drilling program, but the cost of the wells are much higher. The first large diameter wells will still have a high drilling and resource productivity risk. This phase of the exploration program is designed to confirm not only the productivity of the geothermal resources, but also the cost of drilling the well field. There is risk involved in drilling conditions, rock permeability and the risk of losing a well from mechanical failures and collapse of the well casing. The confirmation exploration drilling costs are estimated to be approximately \$15,625,000 and will take two years to complete the drilling of four wells.

Environmental Cost: The exploration program will require a NEPA analysis. The drilling program has been designed to avoid the sensitive areas of the drainage areas of Shitike Creek and Whitewater River. The cost of a detailed environmental assessment for the exploration phase of the geothermal project is estimated to cost approximately \$600,000.

Financial Risk: Between \$14 million and \$20 million may be required to complete the exploration and confirmation drilling phases of the geothermal project; depending upon the number of exploration and confirmation wells needed to reach the Go / No Go decision point for development of the power plant. The following is summary of the estimated program cost required to bring a geothermal project to the power plant development stage.

Slim Hole Drilling:	\$ 3,600,000
Confirmation Drilling:	\$15,625,000
Environmental Assessment:	<u>\$ 600,000</u>
Total	\$19,825,000

Warm Springs Power & Water Enterprises has applied for a grant from the BIA to pay for the initial slim hole drilling program to minimize the risk associated with the \$3.6 million exploration slim hold drilling program. The Tribes may be able to share or defer entirely the drilling risk through cooperative programs with the U.S. Department of Energy (DOE). DOE has several drilling assistance programs which are currently not funded. Funding for these programs depend upon Congressional appropriations and usually requires matching funds. The Tribes should continue to seek federal funds to assist it in the exploration drilling and minimize the financial risk.

Power Plant Development Plan

Power Cycle Selection

Most geothermal developments are either based on flash steam technology or binary technology. Flash steam plants are the most common type of geothermal power generation plants in operation today. They use water at temperatures greater than 360° F (182° C) that is pumped under high pressure to the generation equipment at the surface. Upon reaching the generation equipment the pressure is suddenly reduced, allowing some of the hot water to convert or “flash” into steam. This steam is then used to power the turbine/generator units to produce electricity. The remaining hot water not flashed into steam, and the water condensed from the steam is generally pumped back into the reservoir. An example of an area using the flash steam operation is the CalEnergy Navy I flash geothermal power plant at the Coso geothermal field. See Figure 8 for a diagram of a geothermal flash steam plant.

Binary cycle geothermal power generation plants differ from Dry Steam and Flash Steam systems in that the water or steam from the geothermal reservoir never comes in contact with the turbine/generator units. In the Binary system, the water from the geothermal reservoir is used to heat another “working fluid” which is vaporized and used to turn the turbine/generator units. The geothermal water and the “working fluid” are each confined in separate circulating systems or “closed loops” and never come in contact with each other. The advantage of the Binary Cycle plant is that they can operate with lower temperature waters (225° F - 360° F), by using working fluids that have an even lower boiling point than water. They also produce no air emissions. An example of an area using a Binary Cycle power generation system is the Mammoth Pacific binary geothermal power plants at the Casa Diablo geothermal field. See Figure 9 for a diagram of a geothermal binary power plant.

The primary determinant of the appropriate power cycle for a given geothermal project is the temperature of the resource. The power cycle assumptions and the balance of plant cost estimate for the Warm Springs project was based on the conservative assumptions for resource temperatures. There are four power cycles with potential application at Warm Springs. Each has significant advantages and disadvantages with regard to cost and operational efficiency.

The following is a general outline of the criteria, advantages and disadvantages for each power cycle that was considered in the evaluation.

Air Cooled Binary

- Resource Temperature: 100°C-190°C
- Advantages:
 - Operates with lower temperature resources
 - No steam plumes
 - 100% of produced fluids are returned to reservoir.
- Disadvantages: The most significant disadvantage is that the cooling cycle is less efficient during higher ambient temperatures >70°C. This results in a lower power output at higher ambient temperatures. This factor was discounted because of the elevation of the site which limits the frequency of higher ambient temperatures to mid-day for a 30 day period in the summer months.

Water Cooled Binary

- Resource Temperature: 100°C-190°C
- Advantages:
 - Operates with lower temperature resources
 - More efficient than dry cooling
 - Requires less parasitic power to run the cooling system
 - Heated cooling fluids have potential for secondary heating uses
- Disadvantages:
 - Requires a constant supply of cooling water from shallow water table of streams
 - Creates a steam plume during cool periods

Flash Steam

- Resource Temperature: >190°C
- Advantages:
 - More efficient at higher temperatures
 - Direct use of steam in the turbine
 - Avoids heat exchanger heat lost
 - Requires less parasitic power to run the cooling system
 - Higher net power output per pound of resource produced
- Disadvantages:
 - Requires a constant supply of cooling water from shallow water table or streams to run cooling tower or use of condensed steam for recharge of cooling tower
 - Creates a steam plume during cool periods
 - Evaporative loss reduces amount of fluid returned to the reservoir

Hybrid (Flash With Binary)

- Resource Temperature: >190°C
- Advantages:
 - Can be designed for 100% fluid injection
 - Eliminates steam plums
 - Works well in environmentally sensitive areas
 - Can increase power output
- Disadvantages:
 - Mechanically more complex
 - Has components from both Flash and Binary plants
 - Higher Cost per kWh

The resource temperatures that are assumed for the project area are less than 190°C. Reservoir temperatures in this range will require a binary power plant power cycle. The GeothermEx report has identified that the most likely average reservoir temperature will be in the range of 175°C (347°F). This temperature puts the subject geothermal resource in the mid-range suitable for a binary power cycle. Other considerations that would tend to make a binary cycle the technology of choice include:

- The absence of steam plumes through the use of air fan cooling towers which will reduce project visibility
- The re-injection of 100% of produced fluid, to provide greater reservoir pressure stability and minimize the potential for pollution in adjacent wilderness areas, lakes and streams

The basic assumptions used in the power plant cost estimate are:

- Power Cycle: Binary, Ormat Turbine Generator Technology

- Cooling Cycle: Air Cooled
 - Tube and Shell Condenser and
 - Air Cooled Fan Towers
 - 100% re-injection of fluids with pumps
 - Low non-condensable gas

For the purposes of the cost estimate and analysis the basic power plant cycle involves a high parasitic load on the power plant for well pumping, cooling fans and injection pumps. The gross generation of the power plant is estimated to be 37 MW with a net output of 30 MW.

It is possible that flash and hybrid (flash/binary) cycles could be utilized if reservoir temperatures turn out to be higher than anticipated (for instance, greater than 190°C or 374°F). See Figure 10 for a diagram of the hybrid flash/binary cycle power plant. This would increase the amount of power output per pound of geothermal resource fluids produced and increase power plant cost but decrease the cost per kW hr of the energy produced. The cost estimate uses the conservative assumption that the power cycle will be a binary power plant with temperatures less than 190°C (374°F).

Condenser Cycle Selection

Within the binary temperature range, there is an important choice to be made between air-cooled and water-cooled condensers. Water-cooled binary plants generate higher average power outputs, both because they are not as subject to daily and seasonal oscillations in ambient temperature, and also because they do not have the parasitic load of running fans on air-cooled condensers. The key to the use of water-cooled binary technology is the availability of a constant supply of cooling water. The availability of these surface waters for use in a geothermal plant merits further investigation. If the project develops a shallow ground water source for project construction water and drilling water, then it should consider in the final design the option of a water-cooled condenser. The cost estimate uses the conservative assumption that the cooling cycle will use an air cooled condenser which has a higher parasitic load.

Power Plant Cost

The GeothermEx study also concludes the choice of power cycles may have relatively little impact on project economics. Because of significant advances in binary plant technology and the competitive aspects of flash technology geothermal equipment suppliers, the choice of power cycle has relatively little impact on the capital costs per kW installed. The general state of the industry makes the power plant cost roughly equivalent between flash and binary power plants with some differences that offer a small advantage to flash technology in the cost of cooling systems. The significant factor controlling cost is the reservoir temperature and well productivity. Historically, binary plants were more expensive than flash plants per kW installed, but in recent years, the capital costs for these categories of plants have converged.

At present, an estimate of \$1,800 per kW installed applies reasonably well across the board for turbine, generator, cooling system, control system and transformer. The balance of plant cost of \$1,800 per kW is considered a realistic assumption for installed plant cost at this stage of scoping and planning.

The Development Phase cost estimate included the following assumptions and criteria:

- **12 additional full sized production wells:**
 - 6 additional production wells
 - assumes that two exploration well can be used as production wells
 - assumes 6 wells producing and two spare wells
 - 6 additional injection wells
 - assumes that one exploration well is used as a spare injector
 - Well drilling and completion cost \$3.5 million each
 - Production Well Cost: \$42 million
- **Electric submersible pumps:**
 - 6 additional pumps for new production wells
 - Assumes one pump already exist with the exploration wells
 - Additional Pump Cost \$350,000 per well
 - Total pump cost: \$2.1 million
- **Power Plant and Gathering System:**
 - Assumes 37.5 MW gross output
 - Assumes 20% parasitic load for binary power plant with air cooled condenser
 - Assumes 30 MW net generation
 - Assumes \$1,800 / kW installed
 - \$67.5 million Capital cost for balance of plant
- **Transmission Line:**
 - Assumes interconnection with existing 230 kV line from Pelton Project
 - Assumes interconnection point is near Road P-600
 - Assumes 15 miles of new 230 kV line
 - Assumes \$267,000 / mile install cost of new 230 kV line
 - \$4.5 million Capital cost for transmission line and interconnection
- **Start-Up:**
 - Estimate includes cost plant start-up and administrative cost
 - Assumes \$1 million
- **Spare Parts Inventory:**
 - Assumes \$1 million for spare turbine rotor, down hole pumps and other parts

Total Development Phase Cost: \$117,700,000

Operations and Maintenance

The industry data indicates that the costs for operations and maintenance for binary and flash plants have also converged. The basic assumption of operation and maintenance costs in the range of 2.0 to 2.5¢/kWh applies equally for flash power plants and binary power plants. The significant difference is the parasitic load of the air cooled binary power plants and the pumping requirements for down hole production pumps. The cost estimate uses the conservative assumption that the cooling cycle will have air cooled condensers and the production wells will have down hole pumps. The project will have a gross generation of 37 MW and a net generation of 30 MW because of the high parasitic load.

Power Plant and Well Field Development Schedule

On average in the Western United States the development of a geothermal binary power plant (30-50 MW in size) takes 5 to 10 years to develop depending upon the location, the level of

environmental approvals required and the resource development timeline. The Resource Development Plan in this report estimates that it will take a minimum of four years to complete the exploration slim hole drilling and the drilling, completion and testing of the four confirmation wells. Assuming that the reservoir engineering report confirms that the exploration and confirmation wells have sufficient resource to a power plant, then the activities that are needed to complete the project and bring the power plant on line will include the well field development, engineering, procurement, construction and start up of the power plant and transmission line. These tasks will take an additional three years to complete. A seven year project development schedule is a realistic assumption for a 37 MW (gross) binary power plant on the Warm Springs Reservation in the Mt. Jefferson area. A shorter schedule would not be realistic given the site constraints and exploration investment risk. A longer schedule is more likely if the tribe is to rely on Federal grants to complete the early exploration drilling. Delays in obtaining Federal funds to drill the exploration wells could extend the schedule several more years.

See Figure 7 for a preliminary schedule of the timeline required to develop a 30 + MW project in the Mt. Jefferson area of the Warm Springs Reservation.

Financial Commitments

The Go / No Go Decision Point for the full development of the geothermal power plant will depend upon the project obtaining the following key milestones:

- Reservoir engineering report by an independent reservoir engineer verifying that the confirmation drilling program has confirmed the resource is sufficient to supply a power plant. This reservoir engineering report is a requirement to obtain project financing. This report will also become the basis for the design of the power plant.
- Environmental approval for the power plant, well field and transmission line. Project financing will also require complete documentation that the project has obtained the necessary NEPA compliance and any pre-construction permits.
- Preliminary design and cost estimate. Financial institutions will require a design based cost estimate for the project loans.
- Power purchase agreement for the sale of electrical power. The financial institutions will require that the project has obtained a power purchase agreement.
- Financial model based on the projected capital cost, operating cost and power sales agreement.

In addition to the sunk cost of exploration drilling, the financial commitments required to drill and complete an additional 12 wells to supply the power plant is approximately \$42 million.

The design and construction of the binary power plant, transmission line and geothermal fluid supply system for a power plant capable of gross generation capacity of 37 MW (30 MW net output) will cost approximately \$76 million.

Total investment in the power plant development phase of the geothermal project will be approximately \$117 million.

Transmission and Interconnection Plan

Transmission Requirements

Geothermal resources are base loaded generation facilities. Base loaded power plants provide power 24 hours a day, 7 days a week, 95% of the hours per year over a 30 to 50 project planning life. This is in contrast to “peaker” plants which turn on or off as demand rises or peaks and as dispatched. Other renewable energy resources, such as wind and solar, generate power intermittently and hydro electric power has a seasonal peak generation. Historically, geothermal power plants have operated at a high reliability and availability. The industry average availability is 95% and capacity ratings average between 85% to 99%. Industry wide geothermal power plants operate at between 85% and 99% of rated capacity 95% of the hours per year. Generation with just high availability and reliability makes them ideally suited to provide power for the “base load” of the transmission grid.

Because geothermal projects have very high availability factors they require dedicated transmission capacity to support their high capacity factor. The development of the geothermal resources on the Warm Springs Reservation will require between 10 to 14 miles of new 230 kV transmission line and dedicated 30 MW transmission capacity over existing or new transmission lines from the Reservation to the load centers.

Existing Transmission System

The existing transmission system on the Warm Springs Reservation has limited capacity because of existing loads. This section provides an outline for planning transmission and interconnection for a geothermal project in the Mt. Jefferson area.

- **BPA 230 kV Transmission Lines:** The Bonneville Power Administration (BPA) has two 230 kV circuits that are routed 10 miles north of the geothermal project area. One of those 230 kV transmission lines connects McNary Substation to Santiam Substation near Stayton, Oregon.
- **Portland General Electric 230 kV Lines:** Portland General Electric (PGE) has a 230 kV circuit from the switchyard at Round Butte to PGE’s Bethel Substation near Salem, Oregon.
- **PacifiCorp 69 kV Lines:** PacifiCorp has a 69 kV circuit to Warm Springs from the Round Butte Substation via the Pelton Rereg-dam Switching Station.

Planning Options

Transmission interconnection and the ability to wheel power to the market load centers are significant issues that may affect the timing for geothermal development. Development plans for the geothermal project should include early evaluation of transmission and interconnection options. The ideal transmission path and the eventual wheeling charges for power delivery will depend upon the purchaser of the power. Transmission interconnection studies should be initiated as soon as the exploration program has confirmed the productivity of a commercially viable geothermal resource. In the interim while exploration is ongoing the Tribes should include the following recommendations in its long term planning for transmission on and across the Warm Springs Reservation.

- Any regional plans for new or improved transmission lines across the Reservation should include studies regarding interconnection of the geothermal project and other renewable resource such as the Mutton Mountain Wind Project and the Biomass Project for delivery of power from tribal renewable resources to load centers in the Willamette Valley. Significant economics of scale can be achieved if new transmission lines or improved capacity on existing lines are sized to their maximum capability.
- The Tribes are currently reviewing the possibility of engaging in discussion about joint ownership of existing or new transmission facilities across the reservation. That could assist in accessing the market competitively with this type of resource.

Power flow studies by Elcon Associates (ELCON) for Warm Springs Power & Water Enterprises have identified the following limitations of possible interconnection options for new renewable energy projects on the Warm Springs Reservation.

- **BPA 230 kV McNary Flowgate Transmission Line:** The BPA 230 kV circuits are routed 10 to 14 miles north of the geothermal project area. One of the two circuits connects McNary Substation to Santiam Substation. This circuit is a major path for power transmission between generation plants located east of the Cascade Mountains and load centers west of the mountains. This line is part of four transmission lines that BPA classifies as the “west of McNary Flowgate.” There is limited capacity on this major transmission system which flows power from generating facilities east of the Cascades to the load centers in the Willamette Valley. Interconnection with the McNary Flowgate transmission line would require approximately 10 to 14 miles of new transmission line across the reservation. The length would depend upon the location selected for a new interconnection switch yard.
- **BPA 230 kV Idle Transmission Line:** The other BPA 230 kV circuit option that may be available to renewable energy development on the reservation is the idle circuit of the 230 kV Maupin Station transmission system. This idle circuit runs parallel to the McNary Flowgate line across the Reservation from Maupin Station to the Salem area. This idle 230 kV line is a possible interconnection option. The circuit has been disconnected about two miles east of the Santiam Substation near Salem, Oregon. The use of this circuit would require a new interconnection point and 3-breaker station to create the interconnection necessary to deliver power into the Willamette Valley load centers. BPA estimates that a new \$8 million switchyard would be necessary to interconnect this idle transmission line into the Santiam Substation. Interconnection with the idle BPA 230 kV line would require 10 to 14 miles of new transmission line.
- **Portland General Electric 230 kV Lines:** PGE / Warm Springs Power & Water Enterprises have a 230 kV transmission circuit from the switchyard at Round Butte to PGE’s Bethel Substation. This circuit is 10 miles west of the geothermal project and is fully loaded. Interconnection would require reconfiguration of the existing contracts and load flow from the Pelton Round Butte Project.
- **PacifiCorp 69 kV Lines:** PacifiCorp has a 69 kV circuit to Warm Springs from the Round Butte Substation via the Pelton Rereg-dam Switching Station. Interconnection at this location would require approximately 14 miles of new transmission line to reach the hydro projects.

The transmission alternatives available for Warm Springs Power & Water Enterprises for the development of the geothermal project are limited by the amount of power that can be delivered through the existing transmission lines on the Warm Springs Reservation. Because development of the geothermal project may take seven to ten years the available capacity in the existing transmission lines may not be available in 2014 to 2018 time frame. Long term plans for improved transmission capability across the reservation should include studies regarding possible interconnection of the geothermal project.

Wheeling Cost Considerations

Depending upon the location and Point of Delivery, selected route and customer, Warm Springs Power & Water Enterprises will be required to pay wheeling charges to BPA, PGE and or PacifiCorp. The basic assumption in the geothermal feasibility study is that the power would be delivered to BPA. Wheeling rates are applied to power that is delivered into the grid. Approximately 2% of the power generated would be consumed as losses between the geothermal power plant and the interconnection point. Future project economic models need to take into consideration not only the capital cost of new transmission facilities required to interconnect the geothermal project to the grid but must also take into consideration the cost of “wheeling” power to the customer. The following section presents the charges that can be expected for wheeling and loss reimbursement on the BPA system based on BPA’s 2006 rate schedule:

- Point to Point Demand Rate: \$1.216 / KW-mo
- Scheduling, Control and Dispatch: \$0.203 / KW-mo
- Generation Supplied Reactive: \$0.085 / KW-mo
- Operating Reserves Spinning and Supplemental Power: \$0.000396 / KW-hr
- Regulation and Frequency Response: \$0.00032 / KW-hr
- Transmission Losses: 1.9% of schedule energy

Similar wheeling and delivery cost consideration would be charged by PGE or PacifiCorp.

Potential For Reimbursement of System Cost

Federal Energy Regulatory Commission (FERC) policy allows for reimbursement of system upgrade cost on network facilities by the transmission provider. BPA has adopted in part the FERC practice and BPA will reimburse the network interconnection cost through transmission service credits. If the 230 kV idle circuit is utilized the interconnection improvement cost at Santiam Substation (a new three breaker ring bus) may be reimbursable. Currently BPA applies interest on the outstanding balance at rates established by FERC to determine the duration of wheeling credits. FERC publishes interest rates for refund purposes and current 2006 rates used by BPA is 6.78%. These rates change from quarter to quarter.

Transmission Cost Assumptions

Development of the geothermal project may take seven to ten years. Assumptions on the availability of capacity on the existing transmission systems can only be used as a factored estimate of the approximate cost that may be expected. Market conditions and availability of transmission capacity in the 2014 to 2018 time frame can not be realistically estimated at this time. The following cost factors were used to approximate the geothermal development cost:

- New Transmission Line Construction: Approximately \$4,000,000
 - 15 miles of new dedicated line
 - interconnecting to the existing 230 kV line northwest of the project area.
 - \$267,000 per mile
- Wheeling and Loss Cost: \$5.00 to \$12.00 / MW –hr

Interconnection Planning

As soon as the geothermal project has reached a positive result from the exploration program and has identified the potential utility partner / purchaser of the power output, Warm Springs Power & Water Enterprises should start investigations regarding the transmission interconnection options and cost, interconnection availability can be the limiting factor in a project. Warm Springs Power & Water Enterprises should complete the following task as early in the development process as possible:

- Submit an “Interconnection Request to Transmission Provider”. A written request for an interconnection study should be submitted to the utilities that may be involved in interconnection and wheeling of the power.
- The following information should be included in the interconnection request:
 - Facility location
 - Interconnection location
 - Energy source and conversion technology description
 - Type of generator and specifications if available
 - Generator manufacturer, model name, number and version number
 - Generator nameplate rating in summer and winter in kW and kVA
 - Maximum power export capability requested (net power output at power plant bus bar)
 - Expected delivered power at interconnection and estimated line loss
 - Power factor for each generator
 - Power systems load flow data sheets
 - Reactive power
 - Transformer specifications
 - Single line diagram of the facility and interconnection request
- Hold an interconnection scoping meeting with the utility
 - Exchange information on requirements
 - Discuss the interconnection plans to determine if the plan is possible
 - Determine if a feasibility study is needed or system impact study is appropriate
- Complete interconnection feasibility study
 - The feasibility study will determine if additional facilities are necessary for project interconnection
 - Identify if potential for circuit breaker faults, thermal overloads and voltage limitations that could result from interconnection
 - Conduct an initial review of grounding requirements and electric system protection
 - Estimate the cost of interconnection facilities
 - Complete system impact study to evaluate the impact of the interconnection of the reliability of the transmission grid
- Complete a facilities study
 - The facilities study is a preliminary design study that will support the interconnection agreement

- Complete single line diagram of the interconnection improvements needed for system interconnection
- Prepare design specifications for the interconnection
- Interconnection Agreement
 - An executable interconnection agreement will be based upon the agreed upon facilities upgrades and associated cost and responsibilities identified in the facilities study.
 - Agreement should include
 - Facility upgrade cost
 - Operational and Maintenance cost
 - Other operational fees

Northwest Wind Integration Action Plan (NWIAP)

The North West Power and Conservation Council's recent power plan recommended that 6,000 MW of wind generation may be economically added to the Northwest power grid. Executives at BPA and the Council were concerned over whether such an amount of wind could be accommodated in the system due to the variability of the output of wind generation. As a result, they formed the Northwest Wind Integration Action Plan (NWIAP) to address whether the Council's plan is feasible. Most of the wind resources are east of the Cascade Mountains and would have to be delivered to load centers on the west side of the Cascade Mountains. The North West power system is transmission limited with regard to east – west transfers of power.

A draft of the NWIAP report concludes that at least 6,000 MW can be integrated into the power grid with modest changes to system operations and operating costs. The main reason for this is that the power system must already respond to widely varying consumer demand over hours of the day and seasons of the year. Wind generation will add to that variability, but is not a fundamentally different problem. Most utilities will have little trouble accommodating relatively large amounts of wind. The major concern is the variability of the generation and that there is not enough base loaded generation mixed with the variable load generation to firm up the transmission system. The draft report recommends that delivering 6000 MW of wind to load centers in the Northwest will require additional transmission infrastructure. Major utilities want additional firm capacity mixed with the wind generation to improve system reliability.

There are several transmission paths that are currently considered to be the most critical in interconnecting wind, but there will need to be additional study to determine the most cost effective way to expand transmission capacity in the Northwest. Two of those key paths are the I-5 corridor (Paul-Allston/Allston-Keeler) and McNary-John Day-Big Eddy. The draft NWIAP report does suggest BPA Transmission look at their process of commercial infrastructure expansion with the McNary path as a pilot. In addition, long range transmission planning and new transmission products that can make more efficient use of the existing system, are suggested as well.

The need for additional transmission line improvements may provide the Tribes an opportunity for participation in these improvements. The McNary-Santiam line which crosses the Warm Springs Reservation is part of the McNary-John Day transmission flowgate. Improvements to this transmission line, particularly the decommissioned 230 kV circuit are expected to be a high priority improvement to this contractually congested line. There is a growing need to improve the east – west transmission abilities to integrate both the firm (new gas generation facilities) and the variable (wind) generation facilities located in eastern Washington and Oregon with the load centers in the Willamette Valley and Seattle area.

The Mt. Jefferson geothermal project is strategically located near this line and presents a possible opportunity for delivery of firm base loaded generation into the McNary –John Day transmission flowgate at the midpoint in the transmission line between McNary and Santiam substations. Any joint ownership opportunities would most likely involve joint financing, with BPA retaining control.

Power Marketing Plan

The Power Marketing Plan could equally be applied to the Tribes' wind and biomass renewable energy projects. Although the power market is regional the potential customers who may consider purchasing the power output from the geothermal project on the Warm Springs Reservation are most likely to be those utilities that have transmission systems on or nearby the Warm Springs Reservation which can deliver the power to the regional load centers.

Market Trends

The market for the power output from a geothermal project in the Mt. Jefferson area will be a future market in the 2010 to 2017 timeframe. The energy market for renewable energy in western transmission grid system is changing rapidly with regard to renewable energy resources. The most significant market force that may create power sales opportunities for a geothermal project in the Mt. Jefferson area is the implementation of new laws regarding renewable portfolio standards. The following sections discuss the current and future trends for renewable energy markets and the factors affecting the potential market for power sales from a renewable energy project such as the geothermal project.

Renewable Portfolio Standards

The Renewable Portfolio Standard (RPS) is a flexible, market-driven policy that can ensure that the public benefits of wind, solar, biomass and geothermal energy continue to be recognized as electricity markets become more competitive. The policy ensures that a minimum amount of renewable energy is included in the portfolio of electricity resources serving a state by increasing the required amount over time. The general intent of the nationwide movement to enact RPS is to put the electricity industry on a path toward increasing sustainability and less dependence on fossil fuels. Because it is a market standard, the RPS relies almost entirely on the private market for its implementation. Market implementation will result in competition, efficiency and innovation that will deliver renewable energy at the lowest possible cost.

Renewable Energy Credits, or "Credits," are central to the RPS. A Credit is a tradable certificate of proof that one kWh of electricity has been generated by a renewable-fueled source. Credits are denominated in kilowatt-hours (kWh) and are a separate commodity from the power itself. The RPS requires all electricity generators (or electricity retailers, depending on policy design) to demonstrate, through ownership of Credits, that they have supported an amount of renewable energy generation equivalent to some percentage of their total annual kWh sales. For example, if the RPS is set at 5%, and a generator sells 100,000 kW hours in a given year, the generator would need to possess 5,000 Credits at the end of that year.

Investors and generators make all decisions about how to comply, including the type of renewable energy to acquire, which technologies to use, what renewable developers to do business with, what price to pay and which contract terms to agree to. Generators decide for themselves whether to invest in renewable energy projects and generate their own Credits, enter into long-term contracts to purchase Credits or renewable power along with Credits, or simply to purchase Credits on the spot market. Only the bottom line is enforced: possession of a sufficient number of Credits at the end of each year. The Credit system provides compliance flexibility and avoids the need to "track electrons." Because the RPS applies equally to all generators, it is competitively-neutral.

The states of California and Washington have passed RPS laws. The Oregon legislature has a RPS bill pending before the legislature. The implementation of RPS laws in the Pacific Northwest region could create opportunities for a power purchase agreement for the Mt. Jefferson geothermal project and other renewable projects on the Warm Springs Reservation. The following summaries are provided regarding RPS market opportunities:

Washington RPS

On November 7, 2006 the State of Washington passed an RPS by ballot initiative. Initiative 937 requires electric utilities that serve more than 25,000 customers in the state of Washington to obtain 15% of their electricity from new renewable resources by 2020. There are 62 private and public utilities in the state of Washington and 17 are considered qualified utilities under Initiative 937 and represent 84% of the electricity load in the state of Washington. Utilities subject to the RPS must acquire renewable resources or acquire equivalent renewable energy credits to meet the following targets:

- At least 3% of its load by 2012 and each year thereafter through 2015.
- At least 9% of its load by 2016 and each year thereafter through 2019.
- At least 15% of its load by 2020 and each year thereafter.

The facility must be located in the Pacific Northwest or the electricity from the facility must be delivered into Washington State on a real-time basis. Hydroelectric generation projects are eligible if incremental electricity is produced as a result of efficiency improvements completed after March 31, 1999.

The Washington State Utilities and Transportation Commission, and the Department of Community, Trade and Economic Development are currently adopting rules for implementing the RPS by December 31, 2007.

California RPS

California's RPS was enacted on September 12, 2002 (SB 1078). In 2002 the California RPS required retail sellers of electricity to purchase 20% of their electricity from renewable resources by 2017. This is the most aggressive RPS in the country. Because of increase public demand and the recent California energy supply problems the California Energy Commission and CPUC accelerated this goal of 20% renewable to 2010 and set the state's 2020 goal at 33%. The California Legislature has charged the Energy Commission with developing a tracking system for implementing the RPS.

The Energy Commission initiated a midcourse review of the Renewable Portfolio Standard program in 2006 because the state did not appear to be on a trajectory to achieve the near-term goal of supplying 20 percent of the state's electricity needs with renewable energy by 2010. The Energy Commission in its recent 2006 Resource Report states that California has achieved only minimal increases in renewable generation. Between 2002, the year in which the Renewable Portfolio Standard took effect, and 2005, the percentage of renewable energy in California's generation mix has remained nearly constant rather than increasing by at least 1 percent per year as required under the statute.

The investor-owned utilities in California, including Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric, continue to affirm their commitment to the Renewable

Portfolio Standard but are having difficulty meeting the goals. They claim progress in achieving Renewable Portfolio Standard goals based on contracts they have entered into over the last few years for as much as 3,936 megawatts of renewable capacity. However, only 242 megawatts of those renewable contracts represent new facilities that are on line and delivering electricity today. To meet the goal of 20 percent by 2010, the investor-owned utilities, collectively, will need to add as much as 1,500 megawatts of eligible renewable generating capacity over the next four years beyond what is already under contract.

The state's two largest publicly owned utilities, the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District, have established targets of 20 percent by 2010 and 23 percent by 2011, respectively. To meet their share of the statewide goal of 20 percent by 2010, publicly owned utilities will need to increase the percentage of eligible renewables in their system by several hundred megawatts.

The California Energy Commission reports that achieving the RPS goals in California is hampered by the lack of adequate transmission to access important renewable resources in Tehachapi and the Imperial Valley which are not interconnected to the 500 kV and 230 kV transmission grid that services most of the loads. Several near-term transmission projects in the permitting process are experiencing delays. Disputes over the best plan for configuring transmission projects to allow the full build-out of Tehachapi resources have delayed progress in moving additional transmission projects into permitting.

Finally, cost allocation issues have created uncertainty about cost recovery, delaying additional investments in renewable transmission. The California Energy Commission also reports that current utility procurement strategies have not sufficiently factored in the risk of contract erosion, creating additional uncertainty about the attainment of Renewable Portfolio Standard goals. Many projects with Renewable Portfolio Standard contracts have been delayed, and a number of them have been cancelled. In addition, several of the largest contracts rely on technologies not yet commercially proven at the scale envisioned, raising concerns about these contracts staying on course.

All of these factors indicate that the California RPS market will require significant import of renewable resources from out of state to meeting the California RPS goals

Oregon RPS

In 2006 the Governor of the State of Oregon created an advisory group to help draft legislation for a Resource Portfolio Standard. Warm Springs Power & Water Enterprises was a member of the Governor's working group. The Governor has taken the recommendations of the Renewable Energy Working Group and introduced a bill to create a RPS for Oregon Legislative Counsel Number (LC) 824 establishes a RPS for electricity supply in Oregon. The bill requires that 25% of Oregon's electric load come from new renewable energy by 2025. The bill includes the following provisions:

- The RPS requirement of 25% by 2025 applies to electric utilities and any energy service suppliers that serve at least 1% of Oregon's electric load. This covers Oregon's three investor-owned electric utilities, PGE, PacifiCorp and Idaho Power and the nine largest consumer-owned utilities. Depending on the rate of load growth, this requirement will likely cover most of the new resources needed to meet these utilities' new loads between 2006 and 2025.

- The RPS sets interim targets of
 1. 5% by 2011,
 2. 15% by 2015 and
 3. 20% by 2020.
- Oregon's 28 smaller consumer-owned utilities which serve less than 1% of Oregon's electric load must meet 60% of their retail load growth by the year 2025 with renewable energy. This target can be met by purchasing "green products" offered by BPA. There are interim targets of 20% of load growth in 2015 and 40% of load growth in 2020.
- Eligible renewable resources include wind, solar, wave, geothermal, biomass, hydropower and other renewable resources that were operational after January 1, 1995. Eligible resources do not have to be located in Oregon but must serve Oregon loads.
- The RPS is not expected to increase rates; but a cost cap is built in as a backstop to limit any possible cost impact.
- Compliance with the RPS can occur by owning eligible resources, by buying the output of resources developed by others, or by acquiring Renewable Energy Certificates.
- The public purpose charge administered by the Oregon Energy Trust is extended through 2025. Use of the renewable energy portion of the public purpose charge is limited to small-scale renewable energy projects less than 20 megawatts to encourage diversity of types of renewable energy resources developed.

Oregon Energy Trust

Energy Trust of Oregon, Inc., began operation in March 2002, charged by the Oregon Public Utility Commission (OPUC) with investing in cost-effective energy conservation, helping to pay the above-market costs of renewable energy resources, and encouraging energy market transformation in Oregon. Energy Trust funds come from a 1999 energy restructuring law that required Oregon's two largest investor-owned utilities to collect a three percent (3%) "public purposes charge" from their customers. The law authorized the OPUC to direct these funds to a non-governmental entity for investment. Energy Trust was organized as a nonprofit organization for this purpose and operates under a grant agreement with the OPUC which provides oversight of the Energy Trust.

Energy Trust has its own board of directors, which has adopted the following 10-year (2002-2012) goals:

- save through cost effective conservation 300 average megawatts of electricity;
- save through cost effective conservation 19,000,000 therms of gas;
- help meet 10% of Oregon's generation needs with renewable energy;
- bring energy-saving and renewable energy opportunities to consumers who historically have been underserved;
- help businesses promoting energy efficiency and renewable energy to succeed and thrive; and
- encourage Oregonians to integrate energy efficiency and renewable energy into their daily lives.

To implement these goals the Energy Trust developed several program. To implement the goal of meeting 10% of Oregon's generation needs with renewable energy the Energy Trust developed a utility-scale program that supports the development of large-scale energy projects through cash incentives that buy down the higher costs that are associated with producing renewable energy. Each year, Energy Trust sets aside several million dollars for this purpose, and works with

PacifiCorp and Portland General Electric to select projects that have been proposed as part of those utilities' integrated resource planning.

Utility-scale energy projects must produce at least 10 MW of electric power. Projects that produce that much energy can include large-scale wind, geothermal, bio-power or hydropower resources. Among currently available renewable resources, investment in large-scale wind development has becoming more cost-effective choice for utilities that want to increase the amount of renewable resources in their generation portfolio.

In 2003, Energy Trust collaborated with PacifiCorp and provided a \$3.8 million incentive to support development of a 41 MW wind farm in northeastern Oregon. The Combine Hills project uses 1 MW Mitsubishi turbines that are 55 meters high.

Energy Trust also collaborated with Pacific Power and PGE on their RFP for new energy resources. Also PGE's recent selection to invest in the 75 MW expansion to the Klondike Wind Farm near Wasco, Oregon is a result of an Energy Trust collaboration. The project, consisting of 50 1.5 MW GE turbines, came on line at the end of 2005. Energy Trust is working with PGE and Pacific Power to select more large-scale renewable projects in 2006 and 2007.

Of the funds collected from investor owned utility customers in Oregon, the Energy Trust allocates approximately \$10 million per year to renewable energy projects. These funds can be used to support projects through a loan program, assistance for grant applications, potential co-funding of feasibility analysis and direct financial support for project development. To be eligible for funding from the Energy Trust a project must meet one of the two qualifications:

- Be developed within the service territory of Pacific Power or PGE, or
- Have a Power Purchase Agreement for the sale of renewable energy to Pacific Power or PGE.

Interested Utilities

Warm Springs Power & Water Enterprises has had preliminary discussions with Portland General Electric and PacifiCorp about possible power sales from new renewable resources location on the Warm Springs Reservation. Bonneville Power Administration has also expressed an interest in helping to "facilitate" renewable energy development on the Warm Springs Reservation. Although these utilities have expressed interest in further discussions, the development status of the projects does not warrant serious discussions regarding power sales contracts or transmission facilitation at this time. The following section summarizes the renewable energy programs within Portland General Electric, PacifiCorp and Bonneville Power Administration.

Portland General Electric

Portland General Electric (PGE) is a national leader in creating customer choices for renewable energy. In 2006, the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE) recognized PGE as the 2006 Green Power Program of the Year for its commitment to advancing the development of the nation's green power market. PGE was ranked first in the nation based on major customer milestones reached last year for green power consumption by residential utility customers. More than 40,000 total customers have signed-up for PGE's renewable electricity with greater than 5 percent of its customers signed up for green power. Only six other utilities in the country had enrolled more than 5 percent of their customers. PGE currently has more than 49,000 renewable energy customers enrolled, which is 6 percent of all customers.

PGE's has been the most aggressive utility in the region on the purchase of power from renewable energy. In the late 1990s PGE agreed to purchase the entire output of Oregon's first wind farm, Vansycle Ridge in eastern Oregon. In December 2005, PGE began purchasing the entire output of the new Klondike II wind farm in Oregon. This spring, PGE announced plans to develop one of the largest wind farms in the nation, the 25,000 acre Biglow Canyon, also in eastern Oregon. Biglow was developed by Orion Energy LLC and will be built, owned and operated by Portland General Electric Company.

PacifiCorp

PacifiCorp is one of the largest utilities in the Western United States, serving more than 1.6 million customers in six western states. In 1989, PacifiCorp merged with Utah Power & Light, and continued doing business as Pacific Power and Utah Power. The company was acquired by MidAmerican Energy Holdings Company in 2006. MidAmerican is a privately held energy company controlled by Berkshire Hathaway Inc. (Warren Buffet)

PacifiCorp now consists of three business units:

- PacifiCorp Energy, containing the electric generation, commercial and energy trading functions, and the coal-mining operations of the company, is headquartered in Salt Lake City, Utah;
- Pacific Power, which delivers electricity to customers in Oregon, Washington and California, is headquartered in Portland, Ore.; and
- Rocky Mountain Power, which delivers electricity to customers in Utah, Wyoming and Idaho, is headquartered in Salt Lake City, Utah. PacifiCorp is headquartered in Portland, Ore.

The acquisition of PacifiCorp by MidAmerican Energy Holdings Company increases the utilities ability and knowledge to provide renewable energy based power to its customers. MidAmerican Energy Holdings subsidiaries own and operate 10 geothermal energy plants in California and two in the Philippines, producing a combined capacity of nearly 700 megawatts of electricity from geothermal resources. More than 3,000 megawatts of MidAmerican Energy Holdings Company's energy capability, approximately 15 percent, currently comes from wind, geothermal and hydroelectric sources.

MidAmerican's stated long term energy supply strategy is to develop its coal resources while expanding its renewable energy portfolio. In January 2007 MidAmerican Energy Holdings Company subsidiaries PacifiCorp and MidAmerican Energy Company (Des Moines, Iowa) announced a total of 223.5 megawatts of new wind energy generation, which increases the company's renewable energy portfolio to more than 15 percent of its total electric United States generating capacity. MidAmerican Energy Company recently announced a 123-megawatt wind project in northwest Iowa and PacifiCorp announced it has purchased and will own Leaning Juniper 1, a 100.5-megawatt wind project in the Columbia Gorge region of north central Oregon.

MidAmerican Energy Company leads the nation's investor owned utilities in ownership of wind-powered electric generation and has 695.5 megawatts of wind energy facilities in operation, under construction and under contract in Iowa. In addition, MidAmerican has contracts for 17 megawatts of electricity from independent generating plants using hydroelectric, biomass and methane as fuel.

PacifiCorp's purchase of the 100.5-megawatt Leaning Juniper 1 wind project is part of its commitment to have 400 megawatts of cost-effective new renewable resources in PacifiCorp's

generation portfolio by the end of 2007. Also, PacifiCorp has committed to acquire an additional 1,000 megawatts of cost-effective renewable energy to serve its customers' electricity needs by 2015. In total, PacifiCorp owns, purchases or has under contract 1,704 megawatts of electricity from renewable sources: 1,167 megawatts from hydroelectric; 457 megawatts from wind; 29 megawatts from geothermal; and the remainder, 51 megawatts, from solar, biomass and biogas.

Bonneville Power Administration

Bonneville Power Administration (BPA) is the largest whole sale power marketer in the region with over 6,000 MW of power sales. BPA is a federal agency under the U.S. Department of Energy. BPA serves the Pacific Northwest through operating an extensive electricity transmission system and marketing wholesale electrical power at cost from federal dams. The BPA operates the largest high-voltage electricity grid in the Northwest. Marketing power from 31 federal dams, one non-federal nuclear plant, several non-federal hydroelectric projects, and wind energy generation facilities the BPA provides energy efficiency services to consumers throughout the Pacific Northwest.

Power services are divided into two separate business units.

- The Transmission Services Group operates and owns one of the nation's largest high voltage transmission systems. More than 250 substations and 15,000 circuit miles of transmission lines serve the Pacific Northwest and connect the Northwest to Canada, California and the inland southwest.
- The Power Services Group markets the power generated at 31 federally-owned dams in the Pacific Northwest, one non-federal nuclear plant and several non-federal hydroelectric projects and renewable power plants (primarily wind projects).

BPA also has separate business units that manage the Environmental, Fish and Wildlife programs related to BPA's dams and transmission facilities and an Energy Efficiency program to acquire cost effective conservation. BPA also has a special business unit, The Industry Restructuring Group that addresses issues that cross power and transmission functions, such as consideration of Grid West or other institutional changes to transmission operation and planning, and general transfer agreements for delivery of federal power over non-federal transmission lines.

BPA has engaged in a public collaborative working group called the Renewable Focus Group, consisting of BPA, customers and other interested parties to review BPA's conservation rate credit program and renewable resource activities. This working group is focused on modifying and refining the current BPA program. BPA has proposed to make \$6 million dollars available annually to customers that pursue renewable resource activities.

The BPA proposal will base the renewable rate credits for renewable generation on the difference between resource cost and a Proxy of Avoid Cost. The Proxy for avoid cost is to be set at a value equal to the simple average of BPA's 2007 Flat Block Preferred Rate and the 2007 Mid-C Flat Block market price.

Geothermal Project Marketing Plan

The marketing plan for the geothermal project will be an ongoing effort which can not have any serious contractual considerations until the Exploration Slim Hole phase of the project has been completed and has favorable results. At this point Warm Springs Power & Water Enterprises will begin to explore with regional utilities possible power sale / development agreements. The first opportunities for negotiating a power sales / development agreement will most likely be with

utilities that have existing agreements and relationships with Warm Springs Power & Water Enterprises.

Warm Springs Power & Water Enterprises has a 50 year ongoing working relationships with PGE with regard to the co-ownership and operating agreements on the Pelton Round Butte Hydroelectric Project. Also the closest existing transmission facility to the geothermal project area is the PGE Round Butte to Bethel 230 kV transmission line. The existing relationship and transmission interconnection potential makes PGE a primary candidate for a utility partner.

Warm Springs Power & Water Enterprises and Warm Springs Forest Products Industries also have an ongoing working relationship with both Portland General Electric and Pacific Power regarding power sales from the biomass project at the Warm Springs mill. Pacific Power provides power services to most of the Reservation.

Working with either PGE or Pacific Power will qualify the project for Energy Trust funds.

In the interim while the exploration program is ongoing Warm Springs Power & Water Enterprises will take the following actions as part of a comprehensive plan to prepare the market for development of a geothermal power project from the Mt. Jefferson area:

- Continue to participate in Governor's Renewable Energy Working Group on development of a RPS for Oregon.
- Continue to participate in BPA's Renewable Credit Program review.
- Monitor the implementation regulations for the Washington RPS.
- Contact investor owned and publicly owned utilities in Oregon and Washington regarding their interest in new renewable energy projects to meet RPS requirements.
- Maintain a working relationship with PGE & Pacific Power and continue discussions regarding renewable energy projects on the Warm Springs Reservation.
- Increase Warm Springs Power & Water Enterprises involvement in regional groups involved in transmission access policy.

Upon completion of the exploration phase of the geothermal project and during the confirmation drilling phase (provided that there have been favorable results) Warm Springs Power & Water Enterprises will take the following actions to obtain a power purchase agreement for the Mt. Jefferson geothermal project.

- Respond to Request for Proposals that may be offered by NW Utilities and California Utilities for new renewable energy projects.
- Submit a formal request to PGE for a transmission facilities study.
- Submit a formal request to Pacific Power for a transmission facilities study.
- Seek possible development agreements with PGE or PacifiCorp.
- Request assistance from BPA on facilitating a power delivery agreement for BPA customers with RPS requirements.
- Contact geothermal developers regarding possible co-development opportunities.

Power Purchase Contract Constraints

- **PPC Relationship to Project Financing:** A geothermal project at Mt. Jefferson would most likely be financed with limited recourse financing. The term of the PPC will need to be sufficient to amortize the project debt. In general, the debt amortization period will be shorter than the PPC term. The extra period allows for "work out time" in case the

project encounters financial difficulties in later years. For example, if the PPC term is 20 years, lenders will generally be willing to amortize the debt over a 15 year period. Only the base term of the PPC is taken into account for lender debt amortization because the lender has no assurances that the power purchaser will elect to continue the PPC into a renewal term.

- **Useful Life and Contract Renewal Price:** Financing for a geothermal project usually structures the PPC revenue to pay for the entire capital cost of the project (plus a profit for the developer/owner) during the primary term of the PPC. Because the entire capital cost of the project is amortized over the base term of the PPC, it is possible to eliminate the cost elements related to the project debt from the power price during the renewal terms. Utility customers may require a price reduction in the renewal terms to reflect the elimination of the bank debt. The renewal terms must include sufficient reserves to pay for replacement wells in the second term of a PPC.
- **Effective Date:** The PPC should be binding on the date it is signed to ensure that the buyer of the project output is committed to purchasing the output once the project is built.
- **Commercial Operation Date:** The term of the PPC usually begins on the effective date but the length of the term should be defined by the commercial operation date and extend for an agreed number of years from the commercial operations date. This is an important constraint for geothermal projects because they typically take longer to develop than wind or biomass projects.
- **Test Energy vs. Commercial Energy:** The commercial operations date sets the beginning of the term for the sale/purchase of commercial energy. With any project and particularly with geothermal projects the start-up period and commercial testing period may take several months. The PPC will most likely have different rate schedules for test energy output. The commercial rate for sale/purchase of the plant capacity and energy usually does not apply until the plant and transmission system have completed all necessary operational start-up and testing periods and are authorized and able to operate and deliver energy in commercial quantities to the point of delivery.
- **Commitment to Develop:** A PPC usually makes the owner/developer of the project fully responsible for the development and operations. The buyer of the power tends to view the PPC as a “put” or an option to require the buyer to purchase project output upon delivery. The buyer usually insists that the project owner/developer that is selling the project output make some form of commitment to develop the project and the timeframe for development. The buyer needs reliability to meet power load requirements and want to have achievable milestones by which to measure the project progress.
- **Termination before Commercial Operation Date:** The PPC should include an “off-ramp” provision that enables the Tribes to terminate the PPA if certain events occur or fail to occur which makes development of the project impossible or not feasible. The termination rights generally include provisions for lack of resource, inability to obtain an interconnection agreement or needed transmission rights, inability to obtain all necessary environmental approvals, inability to obtain project financing and the project’s failure to achieve commercial operation by a certain date. The power purchaser will want to limit the “off-ramp” provisions under which the Tribes could terminate the agreement.

Evidence of reasonable due diligent efforts would need to be provided for the Tribes to satisfy the conditions to terminate the PPC.

- **Point of Delivery:** The PPC will require the energy generated by the power plant to be delivered to a specific point. Because of the remoteness of the geothermal area, it is very likely that the power purchaser will take delivery at the bus bar at the power plant and the point of delivery will be some distance from the plant. The Tribes will be responsible for securing the required transmission to that delivery point which will most likely include construction of 10 to 14 miles of new transmission line and necessary grid improvements needed to interconnect and flow the power down stream to the point of delivery. The project will also have to account for transformer and transmission line energy losses which could affect economic modeling results.
- **Environmental Attributes (Green Tags):** The geothermal project will have environmental attributes which are credits that have market value. Such credits include benefits for emissions reduction, off sets and allowances resulting from avoidance of emission of gas, chemicals or other substances together with the right to report those credits. These environmental attributes are called “green tags or renewable energy credits”. The PPC should clearly state whether the energy from the geothermal power plant is being sold with or without the green tags. The higher PPC price usually accounts for the sale of the green tags. The Tribes will have to warrant its title to the attributes, but should not warrant the future use or value of the green tags beyond the primary term of the contract. Also the assignment of federal and state tax credits or other financial incentives should not be warranted as part of the green tags.
- **Milestones and Delay Damage:** The PPC often includes a schedule of milestones by which the purchaser of the power output can measure progress toward the commercial operations date. The typical milestones include dates by which the project will:
 - Complete reservoir engineering report
 - Obtain approval of pre-construction environmental reports
 - Obtain approval of pre-construction permits
 - Secure project financing
 - Secure transmission interconnection agreements
 - Start site construction
 - Order the turbine generator and other major equipment
 - Start –up and Testing
 - Obtain approval of all operating permits
 - Begin Commercial Operations

Typically a PPC will contain some form of financial penalty if a critical milestone is missed or the contract terminated. Negotiations on termination damages are a key aspect of the PPC. The project wants assurances that the buyer will not withdraw leaving the project with orphaned debt. The buyer wants assurances that the PPC will deliver power and early termination is not a method to restructure the sale with a higher price or to move the PPC to another buyer with a higher price.

- **Output Guarantees:** The PPC may include an output guarantee to the buyer. An output guarantee requires the project to pay the buyer if the project’s output over a specific period of time fails to meet the specified level. Such guarantees may include delivery of

a minimum capacity at critical periods such as peak demand. The PPC will need to address how schedule maintenance, outages, dispatching, grid related forced outage, force majeure events are taken into account with regard to meeting output guarantees. Mechanisms for determining the amount of liquidated damages should be included in the PPC.

- **Termination Rights By Buyer:** To protect against chronic problems at an unreliable plant, the PPC usually allows the buyer to terminate the PPC if the plant's output or availability fall below the minimum contract amount for a specific number of years or chronically violates environmental and permit conditions.

Environmental Plan

“We the people of the Confederated Tribes of Warm Springs, since time immemorial, carry forth the inherent rights of sovereignty and spirituality through unity and a respect for the land, water, each other and the many gifts given by the Creator.”

(Source: The Peoples Plan a Comprehensive Plan for the Year 2020)

The Peoples Plan was adopted by the Tribal Council in 1999 and is intended to be a 20 year comprehensive plan that represents the community’s values and visions for the Tribes’ future through clearly established goals. The five key goals established in the Peoples Plan are:

- To leave our resources in a better condition that when we received them.
- Protect and enhance cultural resources and values where root digging areas, huckleberry fields and other cultural plant sources provide sustainable harvests for tribal member subsistence and traditional uses.
- Manage for all resources and uses through an integrated approach that recognizes the importance of diversity and long-term productivity.
- Provide for sustainable economic and employment opportunities for current and future generations through wise use of natural resources.
- The Confederated Tribes are viewed as a national leader in ecosystem management and cultural resource interpretation.

These five goals describe what the Tribes want in their future in broad terms and establishes a common path for the tribal community members and tribal government to collectively work to achieve. All of these goals establish a strong environmental and natural resource planning ethic. The proposed geothermal project must be planned and developed in such a way as to meet and exceed the Tribes’ expectations for “wise use of natural resources”, environmental protection and ecosystem management while providing sustainable economic opportunity for current and future generations.

To achieve these goals the geothermal project will have to meet a high standard for environmental compliance. The following section discusses the potential areas of environmental concern that are often associated with geothermal development.

Environmental Impacts

Geothermal power plants do have some environmental impacts which are localized. These impacts should be balanced against other power generation options that are being considered in the region such as increasing the regional dependence on gas fired or coal fired power, rejuvenation of nuclear power plant development and further demands on the hydroelectric system at the expense of fisheries mitigation. The localized impacts of geothermal energy development should be balanced against geothermal energy’s advantages over conventional power sources when conducting assessments of power plant project environmental impacts. The primary impacts of geothermal plant construction and energy production are gaseous emissions, land use and habitat impacts, increased noise and potential ground subsidence.

Gaseous Emissions: Geothermal fluids contain dissolved gases, mainly carbon dioxide (CO₂) and hydrogen sulfide (H₂S), small amounts of ammonia, hydrogen, nitrogen, methane and radon, and minor quantities of volatile species of boron, arsenic, and mercury. Geothermal power provides significant environmental advantage over fossil fuel power sources in terms of air

emissions because geothermal energy production releases no nitrogen oxides (NO_x), no sulfur dioxide (SO₂), and much less carbon (CO₂) than fossil-fueled power. The reduction in nitrogen and sulfur emissions reduces local and regional impacts of acid rain and reduction in carbon-dioxide emissions reduce contributions to potential global climate change. Geothermal power plant CO₂ emissions can vary from plant to plant depending on both the characteristics of the reservoir fluid and the type of power generation plant. Binary plants such as the one proposed for the Mt. Jefferson area have no CO₂ emissions because the geothermal system is a closed loop where 100% of the geothermal fluid is re-injected back into the geothermal reservoir. Some CO₂ and H₂S emissions occur during well testing and occasionally when the power plant is in start up or shut down when well venting may be required. On average in the geothermal industry flash steam plants have CO₂ emissions on the order of 0.2 lb/kWh, less than one tenth of the CO₂ emissions of coal-fired generation.

Comparison of CO₂ Emissions by Power Source

Power Source	CO ₂ Emissions (lb/kWh)
Geothermal	0.20
Natural gas	1.321
Oil	1.969
Coal	2.095

Source: DOE, National Renewable Energy Lab 2002

Hydrogen sulfide emissions do not contribute to acid rain or global climate change but H₂S does create a sulfur smell that some people find objectionable. The range of H₂S emissions from geothermal plants is 0.03–6.4 g/kWh. Hydrogen sulfide emissions can vary significantly from field to field, depending on the amount of hydrogen sulfide contained in the geothermal fluid and the type of plant used to exploit the reservoir. If the geothermal resource at Mt. Jefferson was of high enough temperature to warrant the use of flash steam technology then the removal of H₂S from geothermal steam would be a mandatory requirement to comply with Oregon and EPA regulations for air quality. The most common process is the liquid redox process, which produces pure sulfur as a by-product and can be used as an agricultural fertilizer feed stock which can be sold as a secondary by-product. The liquid redox process is capable of reducing H₂S emissions by more than 95%. Binary power plants do not require air emissions control systems because the geothermal resource is kept under pressure from the production wells, through the heat exchangers with the binary fluids and on to the injection wells where the geothermal fluids are returned to the geothermal reservoir. Air quality impacts are expected to be minimal and only during the well testing and plant start up phases.

Landscape and Habitat Impacts: Geothermal power plants require relatively little land. Geothermal installations don't require damming of rivers or extensive forest clearing and there are no mineshafts, tunnels, open pits, waste heaps or oil spills. An entire geothermal field uses only 1–8 acres per MW versus 5–10 acres per MW for nuclear plants and 19 acres per MW for coal plants.

Geothermal power plants are clean because they neither burn fossil fuels nor produce nuclear waste. Around the world geothermal plants have been sited in farmland, parks and forests and have been found to be able to operate with very little impact on local wildlife. For example, the

Hell's Gate National Park in Kenya was established around an existing 45-MW geothermal power station, Olkaria I. Land uses in the park include livestock grazing, growing of foodstuffs and flowers, and conservation of wildlife and birds within the park. After extensive environmental impact analysis, a second geothermal plant, Olkaria II, was approved for installation in the park in 1994, and Olkaria III is currently under construction with little or no impact to critical big game habitat of the park. The EIS for the Newberry Geothermal Project near Lapine, Oregon found that the proposed 30 MW project would have no significant impact on elk and deer habitat in the area. The Mammoth Geothermal Project near Mammoth Mountain, California is adjacent to a major ski area and winter elk range. This project has had no appreciable affect on habitat or recreational use of the area.

Geothermal plants can have an impact on water quality when built in critical water sheds. The risk to surface water quality comes from potential spills from pipeline breaks and well testing. Such incidents are rare in the industry. Geothermal power plants have been found to be relatively benign with respect to water pollution. Production and injection wells are lined with steel casing and cement to isolate fluids from the environment thus protecting the ground water system. Spent thermal waters are injected back into the reservoirs from which the fluids were derived. This practice neatly solves the water-disposal problem while helping to bolster reservoir pressure and prolong the resource's productive existence. Impacts to surface waters have come from road drainage, vehicle wrecks which result in spills and from pipeline leaks or breaks. Pipeline breaks are rare and when they have occurred the power plant control systems can sense the pressure loss and shut down reducing the fluid spill. Unless the thermal fluid spills directly into a stream, the industry history of impacts from both minor and major spills has been minor and in all cases temporary with no long term affects.

Noise: Noise occurs during exploration drilling and construction phases. Noise levels from these operations can range from 45 to 120 decibels (dBa). For comparison, noise levels in quiet suburban residences are on the order of 50 dBa, noise levels in noisy urban environments are typically 80–90 dBa, and the threshold of pain is 120 dBa at 2,000–4,000 Hz.⁵⁰ Comparatively the noise level from a typical well drilling and power plant construction operations would be similar to timber harvesting operations that are currently ongoing on the Warm Springs Reservation. Logging equipment involving trucks, skidders, loaders, high lead cable operations and timber falling have noise levels in the same range from 45 to 120 dBa. Site workers can be protected by wearing ear muffs in high noise areas. With best practices, noise levels can be kept to below 65 dBa, and construction noise should be practically indistinguishable from other background noises at distances over a few hundred feet.

Geothermal Exploration and Construction Noise Levels

Operation	Noise Level (dBa)
Air drilling	85–120
Mud drilling	80
Discharging wells after drilling (to remove drilling debris)	Up to 120
Well testing	70–110
Diesel engines (to operate compressors and provide electricity)	45–55
Heavy machinery (e.g., for earth moving during construction)	Up to 90

Source: DOE, National Renewable Energy Lab 2002

Ground Subsidence and Seismic Activity: Some geothermal developments have been associated with ground subsidence. This occurs when geothermal fluids are withdrawn from a reservoir at a rate greater than the natural inflow into the reservoir and the fluids are not re-injected back into the reservoir. This net outflow causes rock formations at the site to compact, particularly in the case of clays and sediments, leading to ground subsidence at the surface. Key factors causing subsidence include: a shallow reservoir, a pressure drop in the reservoir as a result of fluid withdrawal, the presence of a highly compressible geological rock formation above a shallow reservoir and the presence of high-permeability paths between the reservoir and the ground surface. If all of these conditions are present, ground subsidence is likely to occur. None of these conditions are expected at the Mt. Jefferson area. The rock formations in the Mt. Jefferson area are volcanic and not sedimentary and thus have significant rock strength which would prevent subsidence and the resource is expected to be deep. Most cases where subsidence has occurred in the geothermal industry have been in areas where the reservoir is very close to the surface and in sedimentary rock formations. Fluid re-injection can help to reduce pressure drop and hence subsidence, but its effectiveness depends on where the fluid is re-injected and the permeability conditions in the field. Typically, re-injection is done at some distance from the production well to avoid the cooler rejected waste fluid from lowering the temperature of the production fluid and may not help prevent subsidence. BLM regulations require that a geothermal project monitor for subsidence.

The production and injection of geothermal fluids causes seismic activity (earthquakes). The seismic activity that is usually associated with geothermal reservoir production and injection is called micro-seismic activity. Volcanic areas such as Mt. Jefferson are on the ring of fire, a volcanic and earth quake belt that surrounds the Pacific Rim that is associated with the plate tectonics of the earth's crust. By its very nature Mt. Jefferson is a seismically active area and has micro-earthquakes on a regular basis. Some of this seismic activity is most likely related to the geothermal system. Induced micro-seismic events occur when the underground pressure from production and injection of geothermal fluid changes the underground pressure of the surrounding rocks. It is these local changes in the stress field that induce micro-shears which are opening or closing fractures in the geothermal reservoir rock. In most cases these micro-seismic events can not be detected without sophisticated instruments called geophones which are located deep in observation boreholes. This induced micro-seismicity can actually provide indirect information on the geothermal reservoir permeability. Monitoring of micro-seismicity can provide more

detailed maps of the permeability of the reservoir. In rare cases, production and injection of geothermal fluids can cause an earthquake that is noticeable at the surface. In all historic cases these larger earthquakes have been low magnitude events. The remoteness of the Mt. Jefferson site would mitigate any impacts to structures other than the geothermal facility from an induced seismic event. Such events are generally localized and low magnitude. Because the area is a seismically active area of the earth's crust, natural earthquakes are expected to be orders of magnitude greater than those that could be induced by the geothermal wells. The design specifications for the geothermal facility would have to meet a very high seismic standard because of the current seismic classification of the area. The development approvals for a geothermal project should include a requirement to monitor for seismic events.

Integrated Resource Management Plan (IRMP)

The IRMP was adopted by Tribal Council in 1992. The IRMP team formulated clearly defined parameters to insure high quality preservation of long-term environmentally, archaeologically and culturally sensitive resources. The Tribes' sustained natural resource management philosophy is declared in the IRMP and the natural resource areas of the Reservation have been classified into broad management types such as forestry, range and conditional use. This detailed management plan provides strategies for the stewardship of all forest, water and energy resources and serves as a basis for making management decisions on the Warm Springs Reservation.

The IRMP goals establish an approach to resource management planning that will:

- Preserve, protect and enhance environmental and cultural values.
- Sustain traditional, subsistence and other cultural needs of current and future tribal members.
- Provide for sustainable economic and employment opportunities.
- Provide for health and safety.
- Manage for diversity, long-term productivity and sustainability of all natural resources.

The IRMP classifies the project area as a Conditional Use area. The initial exploration project area is located between the Shitike Creek and Whitewater River canyons. The broader area of geological interest covers the entire eastern flank of Mt. Jefferson. The area is characterized by broad timbered plateaus separated by deep glacial valleys. Most of this area is roadless and excellent habitat for large game such as elk and deer. The upper drainage of Shitike Creek is also a known bull trout habitat area. The project area is a Conditional Use Area under the Integrated Resource Management Plan. The area has limited roads and new roads will be needed to conduct the exploration drilling program.

The IRMP also sets forth best management practices (BMP) that established prescribed methods that should be followed to conserve or protect natural resources. The established BMP in the IRMP are considered standard operating procedures. Managers may deviate from the IRMP when alternative management actions will meet or exceed the intent of the IRMP. The goals, standards and BMP in the IRMP are consistent with the tribal ordinances for comprehensive plans, water, land use, fish and wildlife, agriculture and range management, protection and management of archaeological, historical and cultural resources, wild and scenic rivers, water quality standards and other resource planning documents. Goals, Standards and BMP's have been established in the IRMP for the following resources:

- Water resources and riparian area management
- Fish and aquatic resources management

- Wildlife and wildlife habitat management
- Conditional use area management
- Cultural, historical and archaeological resource management
- Timber and commercial forestlands management
- Forestry related employment management
- Biological diversity in forest management
- Locally rare and culturally significant native species management
- Fire and forest residue management
- Forage resource management
- Recreation and recreation facilities management
- Transportation System Management
- Dead and dying tree management
- Firewood management
- Soil and mineral resource management
- Resource management
- Visual resource management

The IRMP goals, standards and BMP established for each major management area apply to all project development activities. The standards adopted under the IRMP establish minimum guidelines for resource protection. The standards established for various resources under the IRMP establishes conditions to be achieved or maintained, creates conditions to help achieve a goal or objective for a specific resources and establishes a quantifiable management practice.

All natural resource planning on the Warm Springs Reservation occurs at two levels. Level I planning applies to broad areas associated with forest and rangeland management and amendments to the IRMP. Level II planning initiates an assessment of specific activities at the project level and offers specific direction on how the project should be carried out and mitigated. To achieve the most effective management direction under the IRMP, current site conditions and desired future conditions will be considered in the development of the geothermal development plans. An integrated approach to project planning and approval is required under the IRMP before any aspect of the geothermal exploration and development program can be implemented on the Warm Springs Reservation.

The specific process to be followed will depend on a number of factors including complexity, economics, scope, size, design and potential impacts associated with each phase of the proposed geothermal project. The development and approval of a Tribal Project Impact Statement for the geothermal project activities will be required under the IRMP. The Project Impact Statement will follow the same process and steps as a Project Environmental Assessment except that the timelines will not be confined to a six month process and there will be more project scoping. The Project Impact Statement process is utilized by the Warm Springs Tribes for large scale projects that require in-depth planning and analysis such as the Mt. Jefferson geothermal project. All project Impact Statements will be subject to Tribal Council approval.

The proposed geothermal project will require several operating plans under the Geothermal Resources Orders (43 CFR 3200). Each phase of development will require an operating plan that defines the area of operations and the type of operating that will be conducted. The typical operating plans for a geothermal project under the Geothermal Resource Orders are:

- Plan of Exploration: For initial drilling of slim wells and confirmation test wells.

- Plan of Development: For well field development, power plant design and transmission line route selection.
- Plan of Utilization: For power plant operations.

For example the Plan of Exploration will have to include details for road building, well pad locations, size and type of drilling equipment and an estimate of the traffic requirements to support the drilling operations. The impact of the design and operations at each phase of development will be evaluated under the IRMP through either a Project Environmental Assessment or a Project Impact Assessment regarding impacts, mitigation and monitoring requirements to meet the goals, standards and BMP for the each major management area in IRMP.

Environmental Considerations

The development of a geothermal project in the Mt. Jefferson area of the Warm Springs Reservation will require that the project meet very strict environmental standards under the IRMP and will require a detailed environmental assessment of each phase of the development. The following environmental constraints are recommended for the initial exploration phases of the project.

- The Tribes should adopt the BLM's Geothermal Resource Orders which is a comprehensive set of regulations that govern geothermal development on Federal lands.
- The exploration program should submit a detailed Plan of Exploration which describes the specific drilling operations, well casing programs, road requirements and environmental mitigations and precautions.
- All exploration wells should be kept out of the river valleys to avoid any possible impacts to critical habitat and fisheries that are associated with the Shitike Creek and Whitewater River drainages per the IRMP fish and aquatic resources management BMP.
- Additional baseline studies are needed to assess the biological resources of the exploration area. These studies should be site specific to the exploration area but also examine the potential interrelationship the project area may have on resident elk and deer populations per the IRMP wildlife and wildlife habitat management BMP.
- All drilling operations must comply with the standard Warm Springs forestry fire precaution procedures.
- All new roads should be designed to control and minimize storm water run off per the IRMP traffic management BMP.
- A Tribal Project Impact Assessment should be completed for each phase of the geothermal development that reviews the site specific impacts of the proposed activity.
- All future phases of development should complete a detailed Plan of Development and Utilization which describes all aspects of the project design and operations including the transmission line facilities. The Plans of Exploration, Development and Utilization should follow the BLM regulations regarding such plans.
- Tribal Project Impact Assessments should stipulate necessary mitigation to minimize and off-set impacts.
- Any areas of critical habitat or cultural significance should be avoided.

Code of Federal Regulations

The Federal Code of Regulations, Title 25, Volume 1 (25CFR211.1) provides regulations for leasing of tribal lands for mineral, oil and gas and geothermal development. The regulation

(25CFR211.29) provides for exemption of leases and permits made by organized tribes such as the Warm Springs Confederated Tribes, which has a tribal constitution and charter issued pursuant to the Indian Reorganization Act of 1936 (49 Stat. 1250; 48 U.S.C. 461-479). The exception is allowed provided the Tribes have acted by ordinance, resolution or other action authorized under its constitution, bylaw and or charter to provide for such leases. The Tribe can not supersede the requirements of Federal statutes that are applicable to Indian leases. Section 211.29 provides for the application of the regulations specified in Title 25 in so far as they are not superseded by the Tribes actions if the validity of the lease or permit depends upon the approval of the Secretary of Interior.

Because several of the development approvals, including NEPA compliance may require the approval of the Secretary of Interior, through the Bureau of Indian Affairs, the regulations set forth in Title 25 are likely to be applicable to the geothermal project at Mt. Jefferson. The following section is a brief summary of the key aspects of Title 25 that may be applicable or can be used as a guide with regard to geothermal development at Mt. Jefferson.

Section 211.4 Authority and Responsibility of the Bureau of Land Management (BLM).

This section makes specific reference to the BLM regulations with regard to geothermal development including:

- 43 CFR 3260 - Geothermal Resource Operations
- 43 CFR 3280 - Geothermal Unit Agreements
- The BLM geothermal regulations would apply to leases and permits approved under Title 25 by the Tribe and / or BIA. Geothermal exploration and development on BLM, Navy and US Forest Service lands in California, Nevada, Utah and Oregon have been successfully managed by the BLM under the Geothermal Resource Operations regulations. The BLM has a core management team that has been trained in all aspects of geothermal development and supports all Districts of the BLM throughout the western United States.

Section 211.6 Authority and Responsibility of The Minerals Management Service (MMS).

This section makes specific reference to the MMS functions for reporting, accounting and auditing. The authority of the MMS is found in 30 CFR Chapter II, Part A and C. Section 211.6 does provide for the Secretary of Interior to approve alternative provisions for these functions as long as they satisfactorily address the functions governed by MMS regulations. MMS has been managing the collection of royalties from geothermal leases for 30 years and has established procedures and models that can be applied to accounting and auditing a geothermal development on the Warm Springs Reservation.

Section 211.7 Environmental Studies. This section requires the Secretary of Interior to ensure that all environmental studies are prepared as required by:

- The National Environmental Policy Act (NEPA) and the regulations promulgated by the Council on Environmental Quality (CEQ) (40 CRR 1500 through 1508.)
- Archaeological and Historic Preservation Act (16 U.S.C. 469 et. seq.)
- National Historic Preservation Act (16 U.S.C. 470 et.seq.)
- American Indian Religious Freedom Act (42 U.S.C. 1996
- Executive Order 11593
- Protection and Enhancement of Cultural Environment (3 CFR 1971 through 1975)
- Consultation with Advisory Council on Historic Preservation (36 CFR 800)

Section 211.20 Leasing Procedures. This section provides procedures for Tribes to lease their lands for oil, gas, minerals and geothermal purposes. The Tribes may request the Secretary of Interior to prepare, advertise and negotiate the leases on their behalf.

Section 211.24 Bonds. This section sets out the bonding requirements for lessee acquiring a lease or permittee obtaining an assignment of interest. A \$75,000 bond is required for all geothermal leases, permits or assignments. The Tribe and / or Secretary of Interior have the discretion to increase the bond requirements in any particular case.

Section 211.25 Acreage Limitation. This section sets out the size requirements of a lease. A lessee may acquire more than one lease but no single lease may be issued on Tribal lands in excess of one government survey section (640 acres).

Section 211.27 Duration of Leases. This section sets out the following lease duration terms:

- The primary term of a lease of ten (10) years.
- Absent specific lease provisions to the contrary, the lease shall continue as long thereafter as the geothermal resource in the lease are produced in paying quantities.
- The geothermal lease shall continue in full force and effect after the primary term if drilling operations have commenced during the primary term but under no case shall drilling hold a lease longer than 120 days past the primary term without actual production.

Section 211.42 Annual Rentals and Expenditures. This section provides for a yearly development expenditure of not less than \$20 per acre and a rental payment of not less than \$2.00 for each acre in the lease.

Section 211.43 Royalty Rates. This section sets out the criteria for payment of royalty from resource production from a geothermal lease. For geothermal resource the royalty rate criteria are:

1. The primary royalty rate is ten (10) percent of the amount of value of the steam or another form of heat or energy derived from production of the geothermal resources under the lease and sold or utilized by the lessee.
2. Additional royalty rate of five (5) percent of the value of any by-product derived from production of geothermal resources under the lease.
3. Mineral by products associated with geothermal production shall be ten (10) percent of the value at the point of delivery.

Economic and Risk Assessment Summary

Cost Components and Risk

This section breaks down the cost of development and operations of the geothermal power project into its major components and analyzes the various risk factors influencing each cost component, and project financing factors that should be considered by Tribal planners regarding development of the geothermal resources in the Mt. Jefferson area.

Levelized Power Price

The power sale price required for the geothermal binary power plant must be greater than the levelized cost of the project. The levelized costs for the project consist of the sum of the levelized cost of capital investment, and operation and maintenance costs. The levelized cost of capital investment corresponds to the cost associated with the reimbursement of the initial capital investment. The initial capital investment would include the resource exploration cost and the cost of well field development, transmission line construction, power plant construction and any related financial returns, divided by the total output of the facility throughout the entire payback period. In general, the levelized cost of the initial capital investment generally represents a major part (60%) of energy cost for a geothermal project. Comparatively the major component of a gas fired power plant is often the fuel cost. For comparison purposes the financial model for a geothermal project is similar to a hydroelectric project model where fuel cost are low but installed cost are high.

Operating and maintenance costs consist of fixed and variable costs directly related to the electricity production phase. Power plant and steam field operations and maintenance costs correspond to all expenses needed to keep the power system in good working status. Operations and maintenance costs are also strongly affected by site requirements, such as snow plowing and winter maintenance work, and resource characteristics, notably through the resource depth, chemistry, parasitic power requirements and labor cost and occasional well replacements.

Other cost factors that can have a significant affect on the power cost from a geothermal power plant involve:

- the type of capital structure and financial conditions,
- the term (length) of the debt service,
- percent of debt to equity required and
- interest rate available to the Tribes.

All of these cost factors can have major impacts on the resulting power production costs. These financial parameters also impact the cost of the interests paid during construction or the cost related to any time delays.

In addition to the influence of capital structure on power price, other market forces impact the price of goods and services needed during well drilling and plant construction which can also have a significant affect project cost. Availability of drilling equipment, construction material such as steel and other raw material and service costs can become volatile and rise significantly due to market imbalance.

Developing a new geothermal resource is a long and expensive process. Initial development steps involve risky and upfront capital investments in well field development in addition to the power plant construction cost. Unlike natural gas plants, the cost of the gas field and fuel supply is not front end loaded but is instead reflected in the fuel cost. Consequently, a major part of the cost of power is related to the reimbursement of capital invested and associated returns.

In 2001, the Electric Power Research Institute evaluated geothermal power cost and estimated that capital reimbursement and associated interest account for 65% of total cost of geothermal power and found that this cost share compares to typical fuel charges of fossil fuel fired power facilities

Geothermal power development consists of successive development phases that aim to locate the resources (exploration), confirm the power generating capacity of the reservoir (confirmation) and build the power plant and associated structures (site development). Various kinds of parameters will influence the length, difficulty and materials required for these phases thereby affecting their cost.

The initial investment, operations and maintenance cost components are affected by a series of parameters which have yet to be defined for the Mt. Jefferson project. Therefore the cost presented in this report can only be considered an order of magnitude or representative estimate. When possible, cost variability ranges are provided and risks associated with the cost are discussed. The following analysis addresses each development phase, identifying major cost components and analyzing risk factors affecting them.

Exploration and Resource Confirmation Cost and Risk Assessment

Exploration and resource confirmation phases represent only about 15% of the total cost of a successful project but many projects fail at this stage. A high degree of risk evolves from the need for success on the first wells drilled into the reservoir. The extent to which these wells produce hot fluids influences subsequent investment decisions. Although the most expensive element of a geothermal power generation project is the power plant construction, drilling to create the well field that will produce the energy for the power plant involves higher risk than other forms of energy development because of the uncertainties in reservoir characteristics.

The exploration program cost estimate for the Mt. Jefferson project is broken down into two phases, the initial exploration drilling phase involving several deep slim hole wells and other geological investigations and the confirmation drilling phase involving drilling several larger diameter production test wells to test the geothermal reservoir.

The following table summarizes the cost estimate for each phase of the exploration program.

Initial Exploration Phase Cost

Slim Hole Drilling, four wells @ \$1,000,000 per well	\$ 4,000,000
Geophysical Surveys CSAMT	\$ 270,000
Geophysical Surveys, Gravity	\$ 30,000
Roads and Well Pads	\$ 150,000
Well Logging	\$ 40,000
Environmental Assessment and Monitoring	\$ 300,000
Resource Reporting, Drilling Monitoring, Resource Analysis	\$ 75,000
Administration @ 10% of Exploration Program Cost	\$ 487,000
Total Exploration Phase	\$ 5,352,000

Confirmation Phase Cost

Environmental and Permitting	\$ 600,000
Drilling Four Full Sized Confirmation Test Wells, Road, Well Pads, Support Facilities, 8,200 feet @ \$3,500,000 per well	\$14,000,000
Well Testing Two to Four Wells, Includes Purchase of Submersible Pump Submersible Pump for testing: \$350,000 Other well testing cost: \$100,000 per well	\$ 550,000
Reservoir Engineering Reports and Resource Reporting	\$ 150,000
Administration @ 5% of other confirmation cost	\$ 765,000
Total Confirmation Phase Cost	\$16,065,000

Exploration and Confirmation Drilling Risk

The estimated cost for confirming productivity of a geothermal reservoir sufficiently to support project financing is approximately \$21.4 million. The risk to the Tribes can be reduced by utilizing federal grant programs to drilling some of the initial exploration wells. Warm Springs Power & Water Enterprises has applied for a federal grant from the BIA to fund \$3.6 million of the initial \$5.2 million initial exploration effort. The initial \$3.6 million is the highest risk expenditure and favorable results are required from this initial effort before the Tribes should consider additional expenditures for exploration drilling. The confirmation drilling phase will not proceed unless favorable results are obtained from the initial exploration drilling phase. Most lending institutions will require 25% of the total project well field capacity to be confirmed prior to lending any money to a geothermal project. The cost estimate for the exploration and confirmation drilling and testing phases has been designed to reach this 25% goal.

The overall risk of the exploration and resource confirmation phase of the development can be broken down into several sub categories. Of the \$21.4 million program, \$18 million would be used for drilling wells and \$700,000 would be used for geological investigations and resource assessments. An additional \$2.7 million would be cost associated with Tribal administration, environmental evaluations and construction of new roads and repair of existing roads. The \$2.7 million in cost, if carried by the Tribes, could be used as matching funds to obtain additional federal grants for the higher risk drilling programs. The following table is a break down of the exploration program cost by category.

Administration	\$ 1,252,000
Environmental and Permitting	\$ 900,000
New Roads	\$ 150,000
Geophysics and Geology Studies	\$ 300,000
Drilling	\$18,000,000
Well Logging and Testing	\$ 590,000
Resource Reporting and Reservoir Reports	\$ 225,000
Total Exploration and Confirmation Phases	\$21,417,000.

The exploration and confirmation phases mainly consist of drilling exploration and confirmation production wells and testing their flow rates until approximately 25% of the resource capacity needed by the project is confirmed. It also involves reservoir design and engineering and the drilling of some injection capacity to dispose of fluids from production well tests. In addition to confirming the energy potential of a resource, an important characteristic of this phase is linked to its financial component.

Under a private development program that is typical of the geothermal industry all expenses incurred in the exploration and confirmation phases are funded with equity investment. The equity financing portion of a geothermal project can range from 20% to 40% of the over all cost depending upon the total cost of drilling needed to prove 25% of the well field needed to run a power plant. For Mt. Jefferson the 37.5 MW installed capacity would require at least 9.4 MW of geothermal resource productivity in the well head. The GeothermEx report for the Mt. Jefferson site assumes two successful large diameter confirmation production wells will be necessary to meet the 25% criteria.

Industry studies by Idaho National Engineering Laboratory for the U.S. Department of Energy have reported that drilling expenses usually account for eighty percent (80%) of total costs to confirm the resource to meet project financing requirements. The estimated drilling expenses for the resource confirmation program for the Mt. Jefferson project is approximately 84% of the total program cost. The other activities and costs consist mainly of road and pad construction, well testing, reporting, regulatory compliance and permitting and administration.

Two major factors will affect total drilling costs: (1) the cost of drilling individual wells and, (2) the number of wells to drill. The cost of an individual well is mainly related to the depth and diameter of the well as well as the properties of the rock formation. The number of wells to drill is determined by the average well productivity and the size of the project. Well productivity directly depends on the resource temperature and the rock permeability.

The industry averages for geothermal exploration and confirmation drilling cost range between \$300/kW and \$600/kW. The estimated cost to complete the exploration and confirmation phases at Mr. Jefferson is estimated to be approximately \$571/kW installed capacity for the 37.5 MW installed generation capacity projected for a binary power plant at Mt. Jefferson.

Exploration and Confirmation Risk Abatement

As drilling program progresses from the initial exploration phase to the confirmation and testing phase, the development team collects various kinds of data about the resource to increase its understanding of the size, location and behavior of the reservoir. The cumulative information helps site the next wells and improves the probability of drilling successful production wells. The collection and analysis of this data is a critical component of the management program to reduce risk. This data is also a critical component of the reservoir report which documents that the

project has reached the critical 25% of resource production capacity needed by the project for financing.

As each well is completed, industry history has shown that the drilling success rate improves throughout the development phases if the initial exploration wells are successful. The GeothermEx report for the Mt. Jefferson site uses the industry wide historical drilling results to indicate a probability that the first wildcat wells may have a success rate probability of 25%, while the confirmation well drilling may have success rate approaching 60% and the site development drilling success rate is expected to average 70 to 80.

Increased understanding of the geology of the geothermal reservoir can result in significant savings by reducing unsuccessful wells and improving well design or by improving the drilling and well completion programs through increased familiarity with rock formation. Data from every well completion should be used to build an expanding model of the resource.

The highest financial risk for the Tribes will be the cost associated with the drilling required to confirm (prove) that the initial wells are capable of producing at least 25% of the power plant resource requirements. The other criteria generally specified by the financial institutions is that the reservoir models based on the test flows of the initial wells demonstrate that the reservoir has 125% of the resource required for the planned plant capacity. Thus confirmation drilling and reservoir testing is required by most institutional lenders prior to obtaining institutional financing for power plant construction and well field development.

To mitigate or reduce this risk the Tribes should consider the following options:

- Use Federal grants to fund initial exploration drilling. Initial exploration drilling has the lowest success rate and highest risk. Using federal grant to fund these high risk wells will increase the Tribes' understanding of the resource and lower the financial risk.
- Enter into a development agreement with an experience geothermal developer who will take the exploration risk.

Power Plant Development Cost and Risk Assessment

The estimated costs for development of a 37 MW (30-MW Net Output) binary geothermal power plant includes the cost of engineering, procurement and construction of the binary power plant at a remote site near Biddle Pass on the Warm Springs Reservation, the cost of drilling additional wells to supply energy to the power plant, and the cost of new transmission lines to interconnect the power plant to one of the existing transmission lines on the Reservation. The cost estimate also includes administrative, environmental and other associated cost with development of the geothermal power plant, transmission line and well field.

Power Plant and Well Field Development Cost

Total cost for the power plant development phase is estimated to be \$117.7 million which includes \$42 million in additional wells to provide the energy for the power plant. The following table summarizes the estimated cost for each major expenditure category.

Development Drilling: Includes drilling 12 full size wells to 8,200 feet Cost per well including well pads and roads: \$3.5 million	\$ 42,000,000
Additional electrical submersible pumps for 6 production wells Each pump cost \$350,000	\$ 2,100,000
Binary power plant and well field pipeline system 37.5 MW name plate gross generation 20% parasitic load for plant systems Install cost \$1,800 / kW installed name plate rating	\$ 67,500,000
Transmission line 15 miles of new 230 kV Line @ \$267,000 per mile	\$ 4,000,000
Start – up and administration set up	\$ 1,100,000
Spare Parts, spare turbine rotor, extra equipment for road maintenance	\$ 1,000,000
Power plant development cost	\$117,700,000

Well Field Development Risk

The primary risk during the power plant development phase of the project will again be related to well field drilling risk. Well field development costs include all costs associated with completing sufficient wells to supply 125% of the plant energy supply and fluid injection requirements. The GeothermEx report projects that 12 production wells in addition to the wells drilling in the exploration and confirmation stage will need to be drilled to achieve the energy production and injection requirements of a 37.5 MW binary generator. These wells are projected to cost \$3.5 million each.

Well field drilling is inherently risky. Dry hole costs in new well fields can be as high as 20%. The industry average for dry wells is 15%. The cost estimate assumes that a conservative 40% of the wells drilled will not be sufficiently productive to use in the power plant energy supply system. This risk can be mitigated by using the low productivity wells for the injection wells.

A binary power plant requires 100% of the geothermal fluids be injected back into the geothermal reservoir. Depending upon the characteristics of the well, the lowest producing wells can be used for injection wells and injection wells generally can take greater fluid volumes for injection than can be produced with submersible pumps. Therefore fewer injection wells may be required than projected. The cost estimate assumes that the ratio of production to injection wells is 1:1 which is very conservative.

Power Plant Pipeline System Risk

The well field pipeline system is the network of pipes connecting the power plant with all production and injection wells. The cost for these facilities varies widely depending on the distance from the production and injection wells to the power plant, the flowing pressure and chemistry of the produced fluids. Carbon steel pipelines are used in the majority of geothermal resources and can be completely installed for between \$15 - \$25 per inch of diameter per foot of pipe length (example: 24" pipe x 1000 feet x \$20 = \$480,000). Some geothermal fluids are highly corrosive and the cost of pipeline systems that use stainless, high nickel alloys or lined pipe can be two to over five times the cost of carbon steel.

Low and moderate temperature resources ($T < 350$ °F) are usually pumped to enhance well productivity and hot water flow. Production pump costs should be included in the cost of the gathering system. The use of pumps significantly enhances the brine flow and thus reduces the number of production wells needed as well as the overall size of the gathering system. On the other hand, pumped resources have relatively moderate temperatures and, compared to high

temperature resources, require a larger resource flow to provide the same amount of energy to the power system

Site topography and slope stability, average well productivity, size and spread of the well field, and fluid chemistry are the major factors affecting the cost of the well field gathering system. Other important parameters to consider are the site accessibility, road construction needs and winter access difficulties.

Power Plant Risk

Power plant design is a complex activity that balances the need to minimize both construction and operations and maintenance costs with the need to maximize the optimum power generation capacity. Plant engineering consists of defining the optimal size of power plant equipment and choosing the best suited technologies and construction materials to deal with site and resource particularities. Power plant engineering along with resource capacity assessment is a time and resource consuming activity.

Most geothermal resources are unique in terms of site and resource characteristics. As a result, most power plants currently in operation are equally unique. The major technology choices are tied to resource characteristics which can have significant affect on the cost of the power plant. The technology used in geothermal power plants is considered a mature technology and there is a large range of state of the art technologies available that may be used to deal with particular problems. The optimum choice is usually dictated by the resource characteristics (temperature, chemistry, etc.) and power plant environment (weather conditions, water availability, etc.).

This analysis focuses on current technologies for binary power plants and does not address the potential for future advances in technology. There have been significant advances in binary technology in the past five years. The efficiency of binary plant technology has doubled every ten years.

Binary Technology Risk

The temperature of the resource is an essential parameter influencing the cost of the power plant equipment. Each power plant is designed to optimize the use of the heat supplied by the geothermal fluid. The size and thus cost of various components (e.g. heat exchangers) is determined by the resource's temperature. As the temperature of the resource goes up, the efficiency of the power system increases and the specific cost of equipment decrease (more energy being produced with similar equipment). The temperature of the resource also determines the technology choice (flash steam vs. binary). High temperature resources use flash steam power systems, which are usually simpler and less costly. The specific cost of steam plant equipment rises quickly, however, as resource temperature decreases (as a result of efficiency losses) and binary systems become competitive at temperatures close to 177°C (350°F). Despite a more complex design, binary power systems are generally less expensive than steam system for temperatures below 177°C. The specific cost of binary systems also rises as temperature drops.

Site Characteristics and Cooling Systems

Weather conditions and water availability are essential parameters affecting the choice of the power plant heat rejection system. Two different kinds of cooling system exist:

- air-cooled
- water-cooled.

Water-cooled systems are generally considered to be less expensive to build and operate as long as water is cheap and readily available. Binary plants usually inject all the brine back into the reservoir. In order to use a water-cooled system, binary facilities thus require an additional source

of water that can be evaporated. Shallow ground water wells would be required in the Mt. Jefferson area to supply a water cooled heat rejection system. A water cooled heat rejection system involves a mechanical draft cooling tower and this type of cooling system will create vapor plumes.

The high elevation of the Mt. Jefferson area may also allow for an air cooled system. Despite higher construction costs, an air-cooled heat extraction system may be the most cost efficient choice. An advantage of the air cooled system is that the cooling “tower” is usually much lower and less visible than wet cooling towers and don’t emit vapor plumes. The electric output of power plants equipped with air-cooling systems are quite sensitive to diurnal and seasonal weather conditions (air temperature and humidity) and net energy output typically fluctuates 20-25% on both a diurnal and a seasonal basis. The turbine output of a binary power system depends on the backpressure in the plant’s hydrocarbon condenser which, in turn, depends on the cooling potential of the heat rejection system. The cooling potential of an air-cooled system is directly related to the air temperature. Unfortunately, maximal energy output of an air-cooled power plant occurs when the outdoor temperature is low (i.e. at night), while summer peak energy demand typically takes place during the hottest hours of the day (notably due to air conditioning). By contrast, water-cooled systems use the energy required to evaporate water to cool the condenser. Local weather conditions thus affect water consumption used in the cooling process but have much less impact on the power plant energy output than air cooled systems.

Power purchase contracts often have delivery price incentives that allow for higher energy prices for power delivered during peak demand hours. Contracts can also contain penalties for power output fluctuations such as diurnal or season weather related caused power out fluctuations. Such incentives / penalties in the power sales contract can be a critical parameter in the choice of cooling systems for a binary power plant.

Operation costs of air-cooled systems mostly consist of power required by the cooling fan motors. Some maintenance is also needed, but typically consists of an annual check-up of fan motors and belts as well as system lubrication. The parasitic load of an air-cooled system is usually considered to be higher than that required by a cooling tower (electric power needed to spin air fans vs. water pumps and air fans). However, much less work is needed to operate and maintain a well-designed air-cooled system. Water-cooled systems require biotic and sometimes chemical water treatment to prevent algae blooms or mineral deposition. Recent U.S. Department of Energy studies on geothermal power plant operations in Nevada at several power plants have shown that the operations and maintenance costs of air-cooled systems are lower than those of water cooled systems.

Engineering design of the binary power plant will have to make an evaluation of important trade-offs between environmental and visual constraints as well as the tradeoffs between initial construction costs and later operations and maintenance costs for the heat rejection system. The local weather conditions at Mt. Jefferson may also induce delays that will affect construction costs because the power project is located in an area characterized by particularly long snow seasons. Local terrain topography and geologic factors such as slope stability can affect construction costs by another 2-5%.

Soft costs

The developer’s soft costs encompass a series of costs related to project development and financial issues. They generally correspond to 6% to 10% of total expenditures and include all expenses related to engineering, legal, regulatory, documentation and reporting activities.

Another important component of soft costs is the financial charges and fees required to gather the capital needed to finance the project and provisions for overhead costs. Project cost estimates incorporate provisions for contingencies that usually correspond to 10% of total budgeted costs.

Land costs

If the Tribes consider leasing the geothermal project to a developer the project will involve a lease rental and a royalty payment. These costs are considered as operation and maintenance costs rather than capital costs. A clear distinction should be made between surface and subsurface land rights. Surface land leases represent minimal expenditures to lease the ground for the power plant and well field while subsurface mineral rights (geothermal resource production rights) typically correspond to 10% of the value of the raw energy supplied to the power plant. Some private royalties are tied to 2% to 5% of the gross power generated. Resource royalty rights are a significant operations and maintenance cost component.

Labor costs

U.S. Department of Energy studies of the geothermal industry estimated that labor costs account for 41% of total project costs, equipment and materials account for 40% of the project cost and “other” costs respectively represent the remaining 19%. According to the Bureau of Labor Statistics, inflation-adjusted labor cost statistics show that construction labor costs have only increased 9% over the past 20 years. Availability of skilled labor may also be an issue for the Mt. Jefferson project which is located in a remote area of the Warm Springs Reservation. The development may require building construction camps to provide housing and meals to workers, and this may increase labor cost by 8% to 12%.

Raw material costs

Historically raw material and power plant equipment costs account for 40% of the project’s costs. This cost share is however expected to be larger for future projects since raw material prices such as steel have sharply increased in recent years, particularly in response to the high demand of the Chinese economy. The affect of market variability on steel, concrete, oil, wood and other construction materials’ prices has sometimes doubled and this market variability can seriously affect the competitiveness of projects being developed. Assuming that steel costs represent 10% to 20% of geothermal power systems, the doubling in the price of steel (2003-2004 period) would result in a 10% to 20% cost increase for power plant equipment.

Estimated Capital Cost for 37 MW (30 MW Net) Geothermal Project

The total capital cost for the geothermal project would include all cost associated with the exploration and confirmation drilling as well as the power plant, transmission line and well field development cost. The following table summarizes the capital cost of the project.

Initial Exploration Phase	\$ 5,352,000
Confirmation Drilling Phase	\$ 16,065,000
Power Plant, Well Field and Transmission Line	\$117,700,000
Total Estimated Cost (2006 Dollars)	\$139,117,000
Installed Cost Per Gross kW (37.5 MW)	\$ 3,710/kW

Construction Risk

Construction risk is defined as any exposure to possible loss during construction. Every construction project is unique and each offers a multitude of different risks. To ensure success the construction contracts need to recognize, assess and assign these risks to the various parties involved in the project.

Early identification of the risk elements is a key component to construction risk mitigation. For example, the equipment delivery schedule is a risk generally taken by the turnkey contractor. Delays in delivery of the key equipment such as the turbine generator or power plant power transformer could result in significant delays in power plant completion, which would affect the cost and cash flow. Weather is another key risk which may cause delays.

After identifying each risk, the Tribes must decide whether to “share or transfer” each risk to the contractors. A reasoned risk allocation strategy would be one that seeks to allocate specific risk based on an analysis of which party is best able to evaluate, control, manage and assume the risk. An allocation of risk should try to more closely align the interest of the Tribes as the land and resource owner with those of the developer/design and construction teams. Usually one party may accept risks that are foreseeable and that are primarily or exclusively within its control. A key factor on allocation of construction risk is that if a contracting party is contracting parties that are in a position to control or manage a particular risk, they are often in a position to transfer or assign the risk to a third party such as an insurer or surety. For example if the Tribes are unable or unwilling to grant site control to the construction contractor, then it must be willing to assume considerable risk associated with the project site during construction.

In addition to the typical contractual remedies associated with construction projects there are several other processes that can help minimize and / or manage construction risk.

Partnering: The objective of partnering is to improve the project communications and civility through a team building process. Development of the geothermal project on tribal lands will require some form of “partnering” with the developer / construction contractor with regard to site access, interfacing with tribal government, use of tribal roads, and impacts of the tribal community. While the contract establishes the legal relationship, the “partnering” process attempts to create an environment where trust and teamwork prevent disputes and fosters a cooperative atmosphere that leads to a project’s successful completion “on time and within budget”.

Prequalification: Pre-qualifying design professionals and construction contractors reduce the development team’s chance of contracting with unqualified individuals or firms by assessing their capabilities and track record. Geothermal drilling and power plant design are specialized industries requiring considerable experience. Although a single “turnkey” contractor may be selected to design and construct the binary power plant, several aspects of the plant design and construction may require specialized equipment and experience in design and installation. Selecting qualified design and construction contractors will be a key aspect of construction risk mitigation.

Bonds: Bonds are a risk transfer instrument in which a third party, the surety assumes the risk of the contractor’s performance and the risk of the contractor’s payment obligations to certain subcontractors and suppliers for the project. The surety will require a premium payment to cover its risk. Lenders and the Tribes may require that certain risk be transferred to the contractor by stipulating in the construction contracts that the contractor furnish the Tribes with performance

and payment bonds. The contractor's capacity to perform and financial strength are key issues when considering the prequalification of the contractors.

EPC Contracts

EPC contracts can provide for significant project risk reduction to the owner. The key clauses in any construction contract are those which impact on:

- . time;
- . cost; and
- . quality.

The same is true of EPC Contracts. However, EPC Contracts tend to deal with issues with greater sophistication than other types of construction contracts and are generally designed to satisfy the lenders' requirements for bank-ability and assign responsibility. EPC contracts involve the following general terms:

- **Single Point of Responsibility:** The contractor is responsible for all design, engineering, procurement, construction, commissioning and testing activities. Therefore, if any problems occur the project owner need only look to one party - the contractor – to both fix the problem and provide compensation. As a result, if the contractor is a consortium comprising several entities the EPC Contract must state that those entities are jointly and severally liable to the project company. In general the EPC contract will include the following:
- **Fixed Contract Price:** The risk of cost overruns and the benefit of any cost savings are to the contractor's account. The contractor usually has a limited ability to claim additional money which is limited to circumstances where the owner has delayed the contractor or has ordered variations to the works.
- **Fixed Completion Date:** EPC Contracts include a guaranteed completion date that is either a fixed date or a fixed period after the commencement of EPC Contract. If this date is not met the contractor is liable for delay liquidated damages
- **Performance Guarantees:** The project owner's revenue will be earned by operating the power plant. Therefore, it is vital that the power plant performs as required in terms of output and reliability. Therefore, EPC Contracts contain performance guarantees backed by performance liquidated damages payable by the contractor if it fails to meet the performance guarantees.
- **Caps on Liability:** Most EPC contractors will not, as a matter of company policy, enter into contracts with unlimited liability. EPC Contracts for power projects generally cap the contractor's liability at a percentage of the contract price. An overall liability cap of 100% of the contract price is common.
- **Security:** It is standard for the contractor to provide performance security to protect the project if the contractor does not comply with its obligations under the EPC Contract. The security takes a number of forms including:
 - A bank guarantee for a percentage, normally in the range of 5% - 15%, of the contract price.
 - Retention i.e.: withholding a percentage (usually 5% - 10%) of each payment.
 - Bonds: a guarantee or performance bond.
 - A parent company guarantee - this is a guarantee from the ultimate parent (or other suitable related entity) of the contractor which provides that it will perform the contractor's obligations if, for whatever reason, the contractor does not perform.
- **Defects Liability:** The contractor is usually obliged to repair defects that occur in the 12 to 24 months following completion of the performance testing.

- **Force Majeure:** The parties are excused from performing their obligations if a force majeure event occurs. Acts of God such as severe weather, earthquakes, and forest fires are examples.
- **Performance Specification:** Unlike a traditional construction contract, an EPC Contract usually contains a performance specification. The performance specification details the performance criteria that the contractor must meet. However, it does not dictate how they must be met. This is left to the contractor to determine.

Split EPC

One common variation on the basic EPC structure is a split EPC Contract. Under a split EPC Contract, the EPC Contract is, as the name implies, split into two or more separate contracts. The basic split structure involves splitting the EPC Contract into an “Onshore Construction Contract” and an “Offshore Supply Contract”. For example, Ormat is the leading supplier of binary power plants. The binary power plants are designed and constructed in Israel. Ormat is also a leading developer of geothermal resources and power plant projects in the United States and elsewhere in the world. It may want to split the EPC between the on-site construction and the manufacturing. There are two main reasons for using a split contract. The first is because it can result in a lower contract price as it allows the contractor to make savings in relation to onshore taxes; in particular on indirect and corporate taxes in the onshore jurisdiction. The second is because it may reduce the cost of complying with local licensing regulations by having more of the works, particularly the design works, undertaken offshore. Another area that may be suited for a split EPC is the transmission line. The transmission line is a separate turnkey project involving specialized engineering and construction activities that are not at the power plant site.

There are risks to the project in the split EPC structure. This mainly arises because of the derogation from the principle of single point of responsibility. Unlike a standard EPC Contract, the owner cannot look only to a single contractor to satisfy all the contractual obligations (in particular, design, construction and performance). Under a split structure, there are at least two entities with those obligations.

Therefore, a third agreement, a wrap-around guarantee is often used to deliver a single point of responsibility despite the split. Under a wrap-around guarantee, an entity, usually either the offshore supplier or the parent company of the contracting entities, guarantees the obligations of both contractors. This delivers a single point of responsibility to the project company and the lenders. If the manufacturer of the turbines and the balance of plant contractor or the transmission line contractors are separate entities and the primary EPC company will not take the single point of responsibility under a wrap-around agreement then the project lenders will want to be satisfied that the interface issues are dealt with in the absence of a single point of responsibility.

Delaying Turbine Design and Fabrication

Another risk abatement employed in the geothermal industry is to delay the fabrication and delivery order of the key power plant components, such as the turbine and generator, until the well field development has completed and tested wells capable of supplying 50% of the power plant geothermal resources. This risk abatement will cause the project schedule to be prolonged and will increase cost. Depending upon the quality of the reservoir engineering report, lenders may require this milestone before proceeding with procurement of the key equipment. Some project lenders require equipment suppliers to fix the cancellation charges if the project is delayed or terminated because of poor results from well drilling.

Ownership Options

This section will provide an analysis of ownership options which the Tribes can consider and includes a discussion of potential risk and revenues to the Tribes under the different ownership options. The primary options that were examined are:

- Lease tribal land to a non-tribal developer with no tribal investment.
- Tribal development and ownership with the Tribes assuming full risk.
- Joint Development through a build, own, operate concession contract with eventual ownership transfer to the Tribes.
- Joint development through a turn key build, start-up and ownership transfer contract with a non-tribal developer that shelters the Tribes from development risk.
- Joint development through a turn key design construction agreement, with an option for the Tribes to buy out and an option for the developer to continue to operate for a fee.

Lease Tribal Land

The standard approach to geothermal development on federal lands has been to lease the exploration area to a developer that takes all the risk of development. Under the lease approach the Tribes would lease the exploration area to a geothermal resource developer that can finance the exploration and development of the geothermal resource. This is the lowest risk approach for the Tribes and would involve the Tribes issuing a lease to a non-tribal entity that would take all the exploration and development risk. Under the lease approach the Tribes' revenue would be limited to royalty and rental payments. Federal Code of Regulations for geothermal development on BLM and Tribal lands establishes minimum royalty and rental requirements for geothermal leases. The Tribes could establish higher rates and can require the developer to reimburse the Tribes for all expenses related to administering the lease and associated environmental and permitting reviews. The following is a summary of the typical royalty and rental revenues.

A typical lease rental rate is \$2.00 per acre per year. The geothermal exploration area involves an area of approximately 24 square miles in size. This area would involve a lease of approximately 15,360 acres and would generate an annual rental of \$30,720.

A typical royalty rate is 10% of the amount of value of the steam or heat energy derived from production of the geothermal resources. The Mineral Management Service of the Department of Interior has a complex model for determining how this royalty is calculated after discounting the added value of the power plant to estimate the value of resource. This model can generally be estimated as 5% of gross value of electricity sold. A binary power plant with a 30 MW net output sold under a power sales agreement with a price of \$0.08 / kW hr would generate annual royalty payment of approximately \$898,776 per year.

$(30,000 \text{ kW net generation}) \times (95\% \text{ availability}) \times (8760 \text{ hr/year}) \times (90\% \text{ capacity factor}) \times (\$0.08 \text{ per kW hr}) \times (5\% \text{ royalty on power sales}) = \$898,776$

Total rental and royalty revenue from a typical lease agreement would generate approximately \$929,496 per year in revenue to the Tribes.

Tribal Development, Build-Own-and-Operate (BOO)

Tribal ownership and development assumes the Tribes will finance all aspects of the project and assume all exploration and development risk and does not share the revenues with the construction contractors. Under the BOO ownership scenario the Tribes select a resource developer and power plant engineering and construction turn key contractor to manage the project's resource development, engineering, procurement, construction and start-up. The Tribes would finance, construct, own, operate and maintain the geothermal power development from which it would recover its total investment, operating and maintenance costs plus a reasonable return. Under this project ownership and development scenario the Tribes, which own the assets, may assign its operation and maintenance to a facility operator under a separate operations and maintenance contract.

Joint Development With Other Parties

There are several types of joint development agreements that have been used in geothermal development. The best examples of these types of joint development scenarios involve development of geothermal resources in Indonesia and The Philippines where foreign developers obtain concession contracts to develop the geothermal energy with conditions that eventually return the ownership to the national government after a specified period that allows the developer to receive a return on its investment and risk. Three types of joint development agreement are reviewed in the following section.

Build-Own-Operate-and-Transfer (BOOT)

A BOOT is a type of concession contract where the Tribes select a private company (or consortium) to develop, finance, build, own and operate the power project for a designated period of time. After the contract term has been completed, the project is transferred back to the Tribes without compensation or at a depreciated value. The longer the term of the agreement, the lower the project value becomes at the time of transfer. The private developer generally is granted a concession for a fixed term for no less than 10 year and usually does not exceed 30 years. These types of contracts can also contain an option to extend the concession agreement for another 10 year period after the primary term expires. These types of agreements also provide the resource owner an option to buy-out the developer at a negotiate value. A BOOT contract usually includes a contractual arrangement for continued supply of critical parts, technology transfer and training for tribal members. BOOT Contracts can also have a contractual arrangement for continued operation of the facility by the private company but under tribal ownership. BOOT contracts have been used to develop geothermal projects in Indonesia and The Philippines where the local utilities used a 10 year BOOT agreement with a buy out clause that is exercisable after 10 years at market value at the option of the government.

Build-and-Transfer (B&T)

A B&T is a contractual arrangement whereby a project developer undertakes the financing and construction of the geothermal project. The developer retains ownership and site control of the project until after its completion, start up and typically a one year warrantee operation period. The developer then turns the project over to the Tribes which pays the developer on an agreed schedule for the developers total investments expended on the project, plus a reasonable rate of return thereon. The developer is bought out by the Tribes when the project has demonstrated it can operate at capacity and fulfill the payment terms of permanent financing. This type of contract shelters the Tribes from the risk of development but also increases the cost of the buy

out. A typical B&T arrangement is often employed in the construction of any infrastructure or development project facilities which for strategic or political reasons, must be operated directly by the government (i.e. a military facility). Under this project ownership and development scenario the Tribes, after taking ownership of the assets, can operate the facility itself or may assign its operation and maintenance to a facility operator under a separate operations and maintenance contract.

Build-Transfer-and-Operate (BTO)

A BTO is very similar to a B&T contract. Under a BTO contractual arrangement the Tribes contract out the development of the geothermal project to a private entity such that the contractor builds the facility on a turn-key basis. The developer assumes the risk of cost overruns, delays and specified performance risks. The developer provides development and construction financing and the Tribes provide permanent financing that takes out the developer's retained interest. Once the facility is commissioned satisfactorily, title is transferred to the Tribes at a predetermined price at closing of the permanent financing. The private entity however, continues to operate the facility on behalf of the Tribes under a separate long term operating agreement with a term of 5 to 10 years.

Jobs and Benefits

Power plant construction as well as operation and maintenance involve the use of numerous goods and services provided from other economic and industrial sectors. Increased demand for those goods and services will result in indirect and induced employment impacts, both locally and nationwide.

Construction of a geothermal power plant takes about 17 to 33 months and involves many types of skilled workers. On-site construction typically concerns 3.1 person*year jobs per MW. Recent surveys by DOE of geothermal power plants in California indicate the construction of a 30 to 50 MW power project may require 33 months and involve up to 160 workers. Labor requirements vary during the construction period and peak around the nineteenth month of construction. Typically, a majority of the construction and operations and maintenance workforce is hired locally. Once a power plant is built, employment directly related to operation and maintenance corresponds to 0.74 jobs per installed MW.

Applying the industry average factors to the estimated gross 37 MW installed capacity of a binary power plant at Mt. Jefferson would result in approximately 116 jobs during construction and 28 permanent plant operations jobs.

The plant operations jobs are steady and well-paid. Subcontracted workforce typically represents 42% of the power plant operator's own workforce and 30% of total employment involved in power plant operation and maintenance. Recent surveys of the geothermal industry indicate that on average, total employment related to power plant operations and maintenance account for 0.74 jobs per MW. Of these, 0.52 jobs/MW is the power plant operator's own workforce and 0.22 jobs/MW is subcontracted employment. Subcontracted employment involves a broad range of services such as road maintenance, snow plowing, welding services and pump services. These geothermal jobs bring additional revenue streams into the local community and provide new opportunities for economic development (e.g. increased catering and accommodation services, hardware stores, fuel supply, welding, snow removal etc.).

Despite its temporary nature, the construction phase provides similar economic development opportunities and would have a significant impact on the local economies of Warm Springs and Madras, Oregon with the influx of new construction workers, and from supply of construction materials flowing to the project from supply centers in California and elsewhere via Madras and Portland. Economic multipliers capture the impacts of indirect and induced economic development triggered by new projects. The value of the multiplier depends upon the size and characteristics of the economy considered. Nationwide, the economic multiplier effect of new geothermal power projects is estimated at 2.5. This means that each dollar invested in geothermal development will result in an output growth of \$2.5 for the U.S. economy. Statewide the multiplier is typically considered to range from 1.5 to 2. Similar methodology is used to assess indirect and induced employment impacts.

Construction Employment

Building a new power plant typically takes about 17 to 33 months. Since the type of construction activities change throughout the project completion, the type of workers involved in these tasks also evolves. It is important to note that construction jobs are temporary in nature.

Construction employment is often expressed in "person*month" (P*M) or "person*year" (P*Y) units. One P*M corresponds to the workforce of one person working during one month. Similarly, one P*Y correspond to the employment of one person during one year.

Most information dealing with construction employment related to geothermal power projects comes from Environmental Impact Studies (EIS) of new geothermal power projects. However, these documents tend to provide only the peak number of employee as well as the total length of the construction period. The following construction employment projection estimates the distribution of the of workers throughout the construction period for a 37 MW installed capacity binary power plant at Warm Springs and is factored from EIS studies for geothermal projects in California and Nevada.

Schedule Month	Construction Jobs
1	8
2	15
4	15
6	25
8	30
10	50
12	60
14	80
16	80
18	90
20	120
22	120
24	90
26	60
28	30
30	25

Using this projection the total workforce required to build a new 37 MW binary geothermal power plant is estimated to be 1676 person*months. Of the 1676 person*months involved in the construction 10% would be involved in transmission line construction. The projection of 1676 person*months equates to .45 P*M / MW or 3.1 P*Y / MW for the Mt. Jefferson Power plant during a 30 month construction period. This compares to an industry wide average of 37.4 P*M / MW or 3.1 P*Y /r MW of power capacity installed. The numbers presented are consistent with other construction numbers that could be obtained from various EIS and geothermal developers.

In addition to the construction work force the well field drilling program will contribute additional temporary jobs. Assuming two drill rigs will be used to complete all production and injection wells as fast as possible during the non-winter months, the peak drilling work force would be approximately 25 persons per 12 hour shift or up to 50 temporary jobs. Half of these jobs will be contracted drilling personal with specialized skills and will most likely be trained drilling supervisors, tool pushers and drilling engineers from California or Nevada. Approximately half of the work force will be general labor which could come from local sources.

Multipliers

The capital investment and employment opportunities will have direct impacts on the Tribal and regional economies. These impacts will also create indirect and induced impacts of power

projects on the local, state and national economy. These impacts are important to consider since direct investment on Tribal lands will impact other sectors of the reservation and regional economy.

Direct impacts relate to all expenditures associated with construction and maintenance of geothermal power plants. During the construction phase, it corresponds to the total investment associated with the power plant construction. At the Mt. Jefferson binary geothermal power plant the direct impact is estimated to have a total cost of \$117 million. Approximately \$50 million will be spent on equipment procurement from factories out of the region and most likely from international sources. The remaining \$67 million will be spent on labor and construction materials that will have a direct impact on local and regional economies.

During the operation and maintenance phase, the direct impacts relate to all expenditures on goods and services associated with power plant operation and maintenance. For the Mt. Jefferson binary geothermal power plant, the direct impacts of operations and maintenance are estimated to be between \$2 and \$4 million per year.

Indirect impacts correspond to the economic impact that affects all industries that provide goods and services to the industries directly involved in power plant construction or operation and maintenance. Indirect impacts thus quantify the impact of changes in power plant construction or operation and maintenance activities on the industries that supplies it.

Induced impacts would be industries that experience both direct and indirect impacts and often change their employment levels to meet the new level of demand. These employment changes induce changes in income that is spent in the region to purchase goods and services. This income effect is the source of induced impacts.

Multipliers can be used to calculate the relationship between direct and indirect and induced economic impacts. Indirect impacts resulting from a construction investment are however dependant on the size and characteristics of the economy considered.

Local economy multipliers are therefore typically smaller than state or nationwide multipliers. Similarly, wages paid to operation and maintenance workers have a different impact on the economy than construction investments.

The projected affect of a geothermal investment at Mt. Jefferson using the DOE multipliers is that for a dollar invested in the geothermal project it will induce a total output growth to the regional economy of \$1.70. Accordingly, a geothermal investment of \$117 million would result in a growth of output of \$198 million for regional economy and local economies.

Geothermal industry reports indicate that the construction of 1MW of additional geothermal power production capacity in Nevada would result in 24 jobs in the State and up to 50 jobs in the United States.

These values are also consistent with employment multiplier values provided by DOE in 2005 as part of a nationwide survey which projects that each new MW to be installed would generate 5 additional indirect and induced jobs in an rural economy similar to the geothermal areas of northern Nevada, up to 7.5 additional jobs in an economy of the size of California and 10.7 additional jobs nation wide.

Articles dealing with employment multipliers tend to use very different approaches and do not mention if the resulting employment impact is permanent or temporary. The second methodology presented here-above is certainly more conservative but probably more realistic than the first one that provides very large employment figures and probably overestimates indirect and induced employment impacts.

The following table summarizes the possible direct and induced economic impacts in the Warm Springs area.

Phase	Peak Contractor Employees
Exploration Drilling Phase (1 slim well rig)	10 -15 temporary workers for one year
Confirmation Drilling Phase (1 full size rig)	25 -30 temporary workers for two years
Development Drilling Phase (2 full size rigs)	50 - 60 temporary workers for two years
Power Plant Construction	90-120 workers for two to three years
Transmission Line Construction	10 -15 temporary workers for 1 year
Power Plant Permanent O&M	25 -30 permanent full time workers
Power Plant Construction Expenses Local	\$67 million
Power Plant Equipment Out of Region	\$50 million

Recent studies by the geothermal industry have shown that geothermal resources tend to be located in rural areas with few employment opportunities. Because geothermal energy must be developed where the resource is located, geothermal power plants tend to benefit these economically depressed areas by providing jobs, stability and revenue. Similar impacts should be expected in the Warm Springs and Madras area from a geothermal development on the Warm Springs Reservation.

A geothermal project typically involves a 30 year power sales agreement that provides jobs that can be guaranteed for decades presuming the plant does not suffer financial problems. The Warm Springs Reservation is a rural community that faces many unique challenges. The decline in timber revenues has resulted in a lack of stable, secure, long-term jobs which leads many young adults with “the most education and the greatest earning potential” to emigrate, leaving a poorer, older and smaller population. Reliance on a single primary source of revenue, such as lumber manufacturing can contribute to unemployment and economic instability. Geothermal development may offer an important means of diversifying the economic base of the Warm Springs community.

The jobs within at a geothermal facility cover a broad spectrum of skills, and draw from a diverse selection of applicants. People employed by the geothermal industry include welders; mechanics; pipe fitters; plumbers; machinists; electricians; carpenters; truck drivers; construction and drilling equipment operators and excavators; surveyors; architects and designers; geologists; hydrologists; chemists; electrical, mechanical, and structural engineers; HVAC technicians; plant operators; business managers; computer techs; accountants; attorneys; regulatory and environmental consultants; and government employees.

Geothermal development can have a major impact on local economies. A recent example is the development of the Salton Sea Unit 6 project in Imperial County, California. This 215 MW geothermal project will be the largest renewable energy project in the United States and according to congressional testimony by its owner, MidAmerican Energy Holdings Company; it will employ 550 construction workers and eventually more than 60 “high paid, fulltime operator positions”. Testimony by county commissioners concludes that the plant will represent the single

largest capital investment in Imperial County which is the most economically disadvantage county in California. It should be expected that full development of a 30 to 50 MW project on the Warm Springs Reservation would have similar economic impacts to the Warm Springs and regional economies.

Recommendations

1. The GeothermEx assessment of the Mt. Jefferson geothermal resource area indicates that there is a significant amount volumetric heat in place and other evidence indicates that there is a good probability (90% confidence level) that one or more geothermal reservoir existing in the Mt. Jefferson area which could support between 20 and 50 MW of power generation. The economic potential of the geothermal resource can only be speculated at this time because of the lack of test wells needed to confirm the geothermal resource. Therefore a prudent exploration drilling program is recommended to test this area to assess the size and the economic potential of the geothermal resource.
2. The recommended exploration program would involve drilling of two deep exploration slim wells in the upland areas south of Shitike Creek canyon. This drilling program should be combined with a broader regional geophysical exploration program across the entire eastern flank of Mt. Jefferson to the southern boundary of the Reservation.
3. The completion of the initial exploration wells will bring the Tribes to the first of a series of Go / No-Go decision points regarding the risk associated with developing the geothermal resource. It is recommended that the Tribes retain 100% control of the project until the initial exploration drilling has been completed and the test results evaluated. At this point the Tribes can assess if the project warrants further exploration and further investment by the Tribes or if the Tribes should provide a concession to a geothermal developer who will take the development risk.
4. It is recommended that Warm Springs Power & Water Enterprises should seek federal grants to drill these initial exploration wells to minimize the risk to the Tribes. The Tribes should not commit to a concession or exploration lease with a non-tribal entity until the results of the initial exploration drilling have been evaluated or unless federal grants can not be obtained to drilling the exploration wells.
5. The next major Go / No-Go decision point would involve drilling at least two deep large diameter confirmation wells. These wells will cost several million dollars each and are considered high risk. The project's exposure to confirmation risk up to the point of completing the confirmation wells would be the cost of the slim hole drilling and the additional cost of the larger confirmation wells and any incremental cost for completing the EIS and associated reporting and administrative costs. The sunk cost to obtain sufficient resource information to judge if the project is economical to develop would be approximately \$8.5 million. It is recommended that the Tribes seek a concession partner with a qualified geothermal development company to complete the confirmation drilling phase.
6. It is recommended that Warm Springs Power & Water Enterprises open discussions with qualified geothermal development companies regarding interest in co-development arrangements which could be acceptable to the Tribes regarding ownership, sovereignty and revenues.

7. The following environmental conditions are recommended:
 - a. All exploration wells should be sampled for water chemistry and non-condensable gas. This information should be used to refine the environmental impact analysis for future phases of the development.
 - b. Exploration drilling should be monitored for noise impacts to obtain background and drilling noise level data for use in future environmental impact analysis.
 - c. The Tribes should adopt the BLM's Geothermal Resource Orders which is a comprehensive set of regulations that govern geothermal development on Federal lands.
 - d. Warm Springs Power & Water Enterprises should develop a Plan of Exploration, per the BLM regulations for review by the BIA and Natural Resources Department. The Plan of Exploration should describe the specific drilling operations, well casing programs, road requirements and environmental mitigations and precautions that will be taken. This Plan of Exploration will become the key project description for all environmental and permit approvals.
 - e. All exploration wells should be kept out of the river valleys to avoid any possible impacts to critical habitat and fisheries that are associated with the Shitike Creek and Whitewater River drainages.
 - f. Additional baseline studies are needed to assess the biological resources of the exploration area. These studies should be site specific to the exploration area but also examine the potential interrelationship the project area may have on resident elk and deer populations.
 - g. All drilling operations must comply with the standard Warm Springs forestry fire pre-caution procedures.
 - h. All new roads should be designed to control and minimize storm water run off.
 - i. An environmental assessment should be completed for each phase of the geothermal development that reviews the site specific impacts of the proposed activity.
 - j. All future phase of development should complete a detailed Plan of Development and Utilization which describes all aspects of the project design and operations including the transmission line facilities. The Plans of Exploration, Development and Utilization should follow the BLM regulations regarding such plans.
 - k. Environmental assessments should stipulate necessary mitigation to minimize and off-set impacts.
 - l. Any areas of critical habitat or cultural significance should be avoided.
8. It is recommended that Warm Springs Power & Water Enterprises will take the following actions as part of a comprehensive plan to prepare the market for development of a geothermal power project from the Mt. Jefferson area:
 - a. Continue to participate in Governor's Renewable Energy Working Group on development of a RPS for Oregon.
 - b. Continue to participate in BPA's Renewable Credit Program review.
 - c. Monitor the implementation regulations for the Washington RPS.
 - d. Contact investor owned and publicly owned utilities in Oregon and Washington regarding their interest in new renewable energy projects to meet RPS requirements.
 - e. Maintain a working relationship with PGE & Pacific Power and continue discussions regarding renewable energy projects on the Warm Springs Reservation.

- f. Increase Warm Springs Power & Water Enterprises involvement in regional groups involved in transmission access policy.
 - g. Increase Warm Springs Power & Water Enterprises involvement in regional renewable energy advocacy groups such as the Renewable Northwest Project (RNP).
- 9. Upon completion of the exploration phase of the geothermal project and during the confirmation drilling phase (provided that there have been favorable results), it is recommended that Warm Springs Power & Water Enterprises take the following actions to obtain a power purchase agreement for the Mt. Jefferson geothermal project.
 - a. Respond to Request for Proposals that may be offered by NW Utilities and California Utilities for new renewable energy projects.
 - b. Submit a formal request to PGE for a transmission facilities study.
 - c. Submit a formal request to Pacific Power for a transmission facilities study.
 - d. Seek possible development agreements with PGE or PacifiCorp.
 - e. Request assistance from BPA on facilitating a power delivery agreement for BPA customers with RPS requirements.
 - f. Contact geothermal developers regarding possible co-development opportunities.
- 10. As soon as the geothermal project has reached a positive result from the exploration program and has identified the potential utility partner / purchaser of the power output, it is recommended that Warm Springs Power & Water Enterprises investigate the transmission interconnection options and cost.
- 11. It is recommended that Warm Springs Power & Water Enterprises evaluate its long term plan for transmission requirements for all current and future energy resources on and across the Warm Springs Reservation including biomass, wind, solar and the geothermal project. Any regional plans for new or improved transmission lines across the reservation should include studies regarding interconnection of the geothermal project and other renewable resource such as the Mutton Mountain wind project and the biomass project for delivery of power from tribal renewable resources to load centers in the Willamette Valley. Significant economics of scale can be achieved if new transmission lines or improved capacity on existing lines are sized to their maximum capability.
- 12. It is recommended that Warm Springs Power & Water Enterprises investigate possible cooperative agreements with BPA and other utilities regarding building new transmission facilities across the Warm Springs Reservation and to site the location of those lines near the geothermal project. There is an increasing need to expand the regional transmission east-west capabilities and it is possible that new transmission lines may be proposed in the near future. As the number of transmission stakeholders involved in new transmission projects increases the unit cost of the transmission goes down for all. The Tribes should consider options involving joint ownership of existing and new transmission facilities across the reservation.
- 13. It is recommended that Warm Springs Power & Water Enterprises maintain an active participant role in any concession or joint development project involving the geothermal resources at Mt. Jefferson to assure the Tribes' interest are preserved and that the developer maintains good lines of communications regarding all aspects of the development and environmental compliance. The Go / No Go Decision Point for the full development of the geothermal power plant will depend upon the project obtaining the following key milestones.

- a. Reservoir engineering report by an independent reservoir engineer verifying that the confirmation drilling program has confirmed the resource is sufficient to supply a power plant. This reservoir engineering report is a requirement to obtain project financing. This report will also become the basis for the design of the power plant.
 - b. Environmental approval for the power plant, well field and transmission line. Project financing will also require complete documentation that the project has obtained the necessary NEPA compliance and any preconstruction permits.
 - c. Obtain Tribal Council approval.
 - d. Preparing a preliminary design and cost estimate. Financial institutions will require a design based cost estimate for the project loans.
 - e. Power purchase agreement for the sale of electrical power. The financial institutions will require that the project has obtained a power purchase agreement.
 - f. Financial model based on the projected capital cost, operating cost and power sales agreement.
14. It is recommended that Warm Springs Power & Water Enterprises open a dialogue with the following geothermal development companies regarding potential interest in working with the Tribes.
- a. Ormat International: Ormat is the world's leader in binary power plant technology and developer of geothermal projects throughout the world. Ormat has shown a willingness and creativity in developing projects which involve complex issues of sovereignty and native cultures.
 - b. California Energy Company: CalEnergy is major geothermal company which is owned by MidAmerican Energy Holdings Company, the parent company of PacifiCorp.
 - c. US Geothermal Inc.: A small geothermal development company that is developing a binary power plant at Raft River Idaho.
 - d. Nevada Geothermal Company: A Canadian Company with mid sized geothermal projects under development in British Columbia, Nevada and Oregon.

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Figure 1. Map of Warm Springs Geothermal Exploration Area

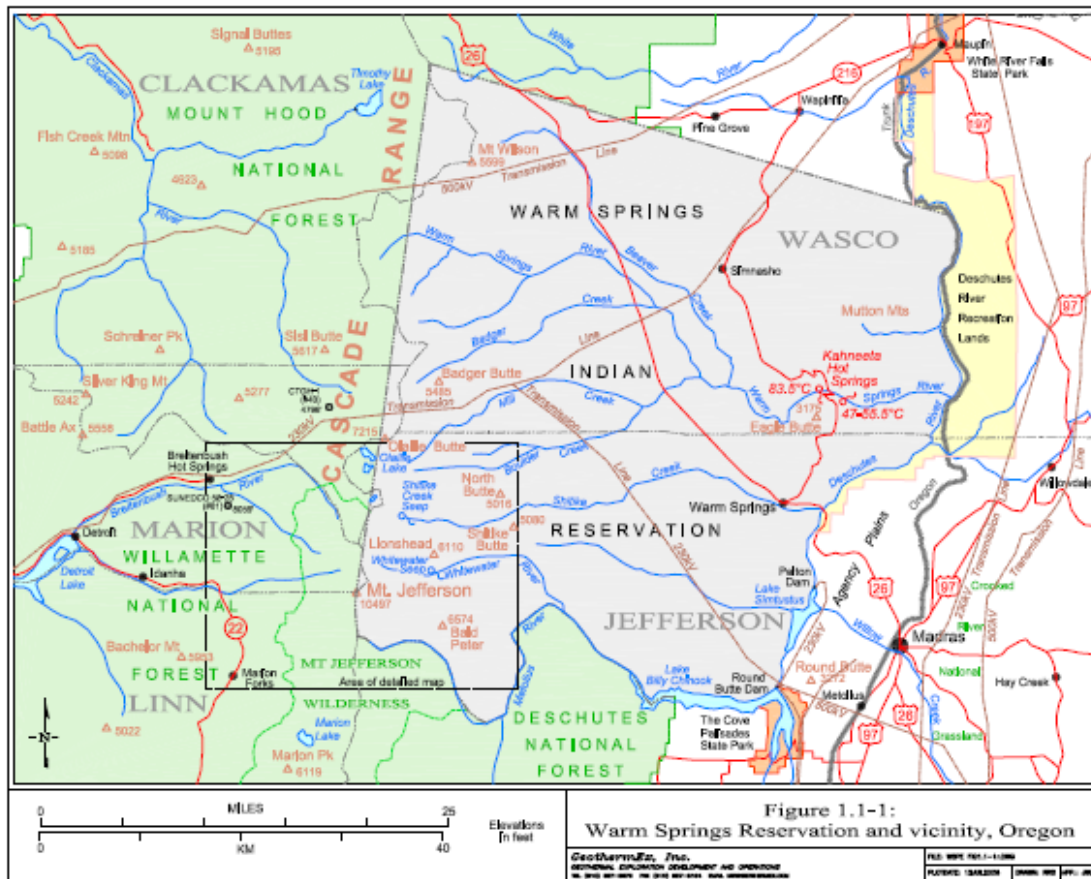


Figure 2. Map of Geothermal Exploration Area

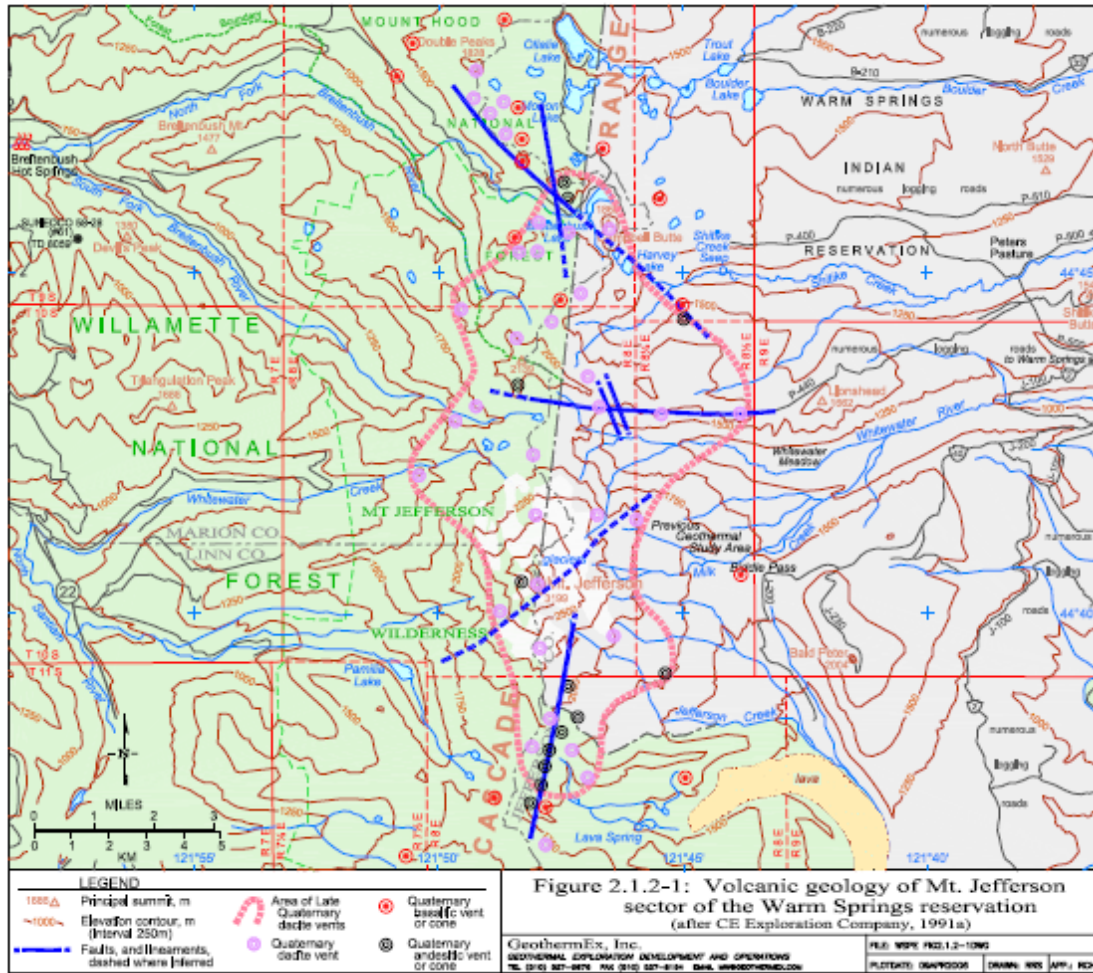


Figure 3. Proposed Location of Exploration Well Drilling Sites

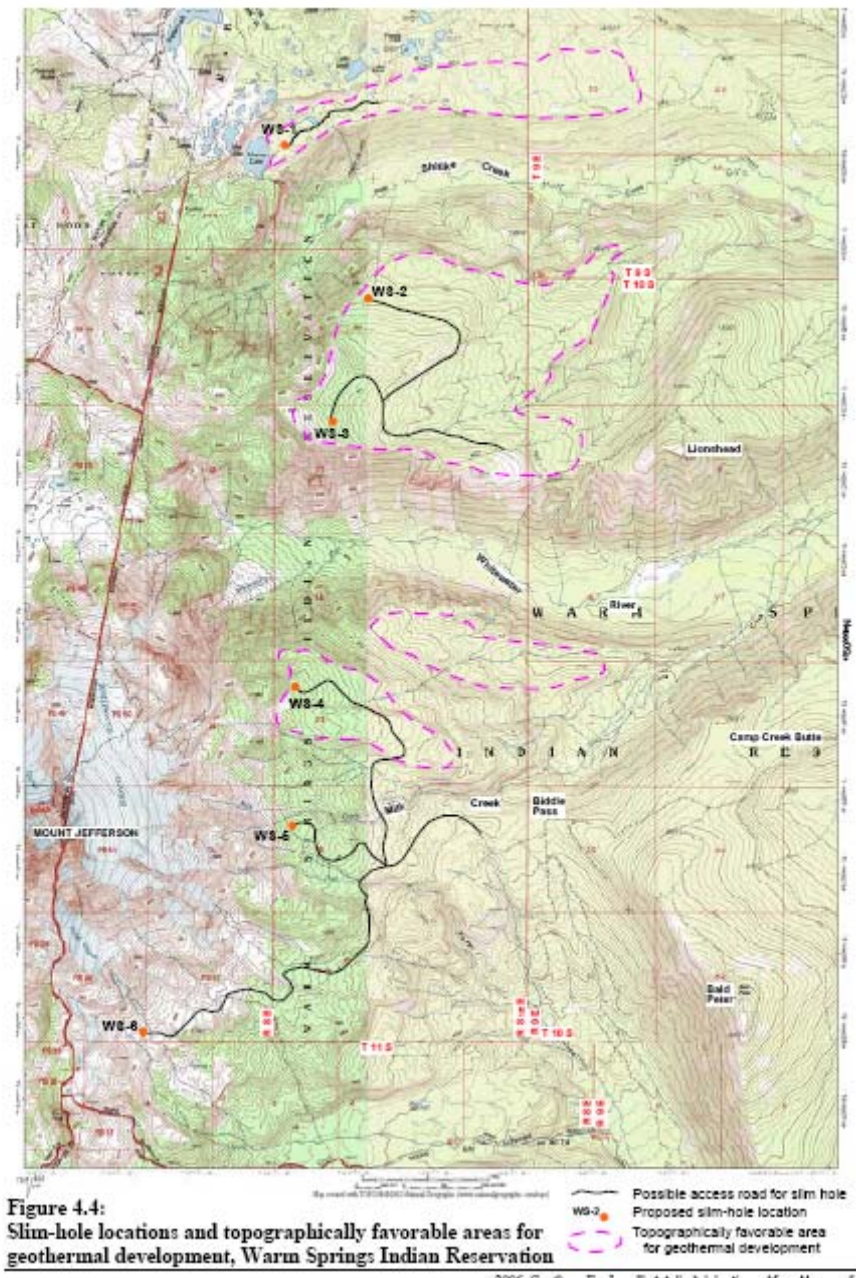


Figure 4. Location of Primary Slim Well Drilling Sites

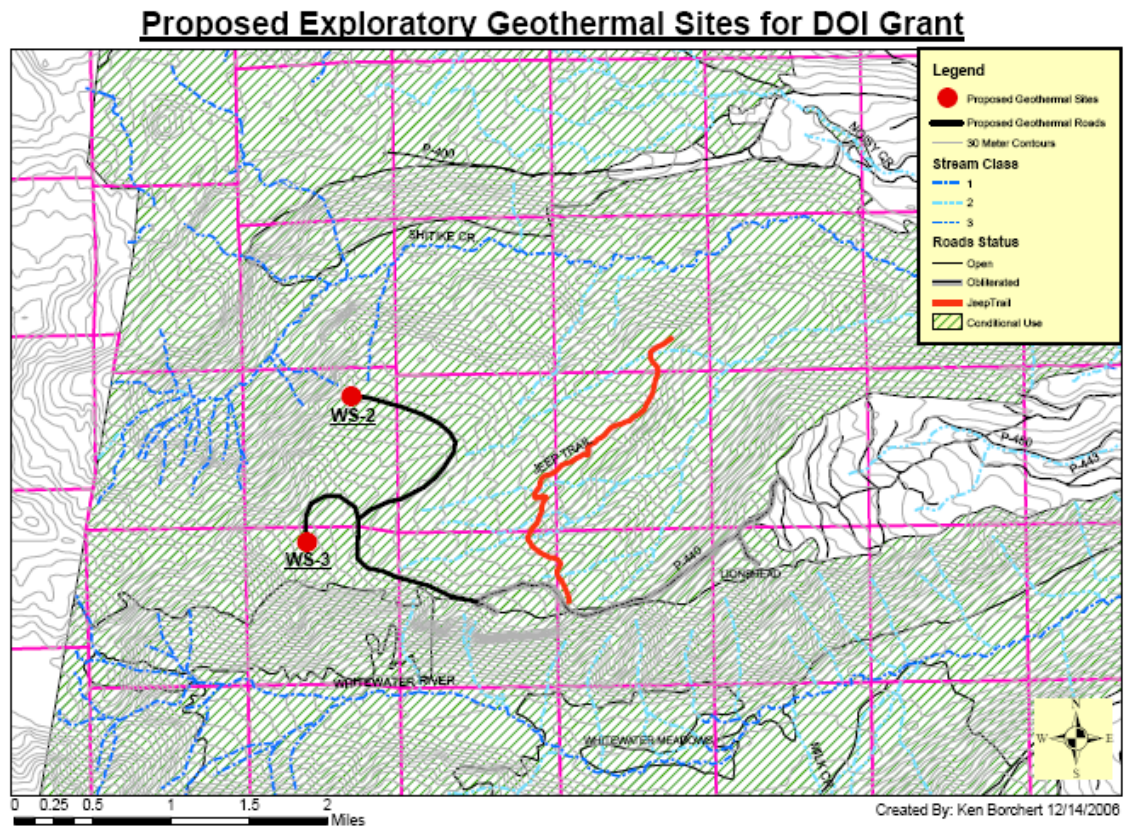


Figure 5. Go / No Go Decision Diagram for the Exploration Program

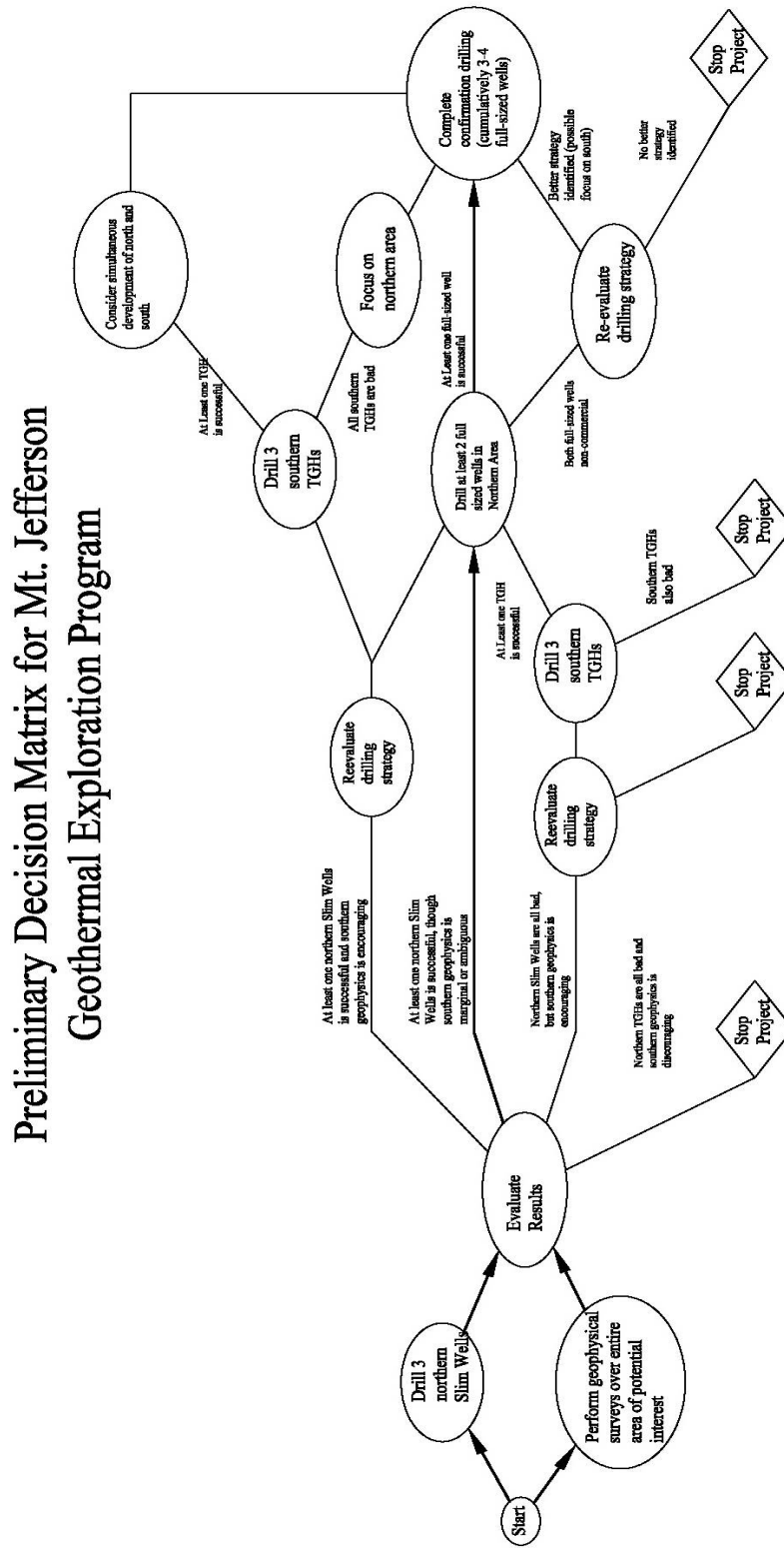


Figure 6. Projected Development Program by GeothermEx

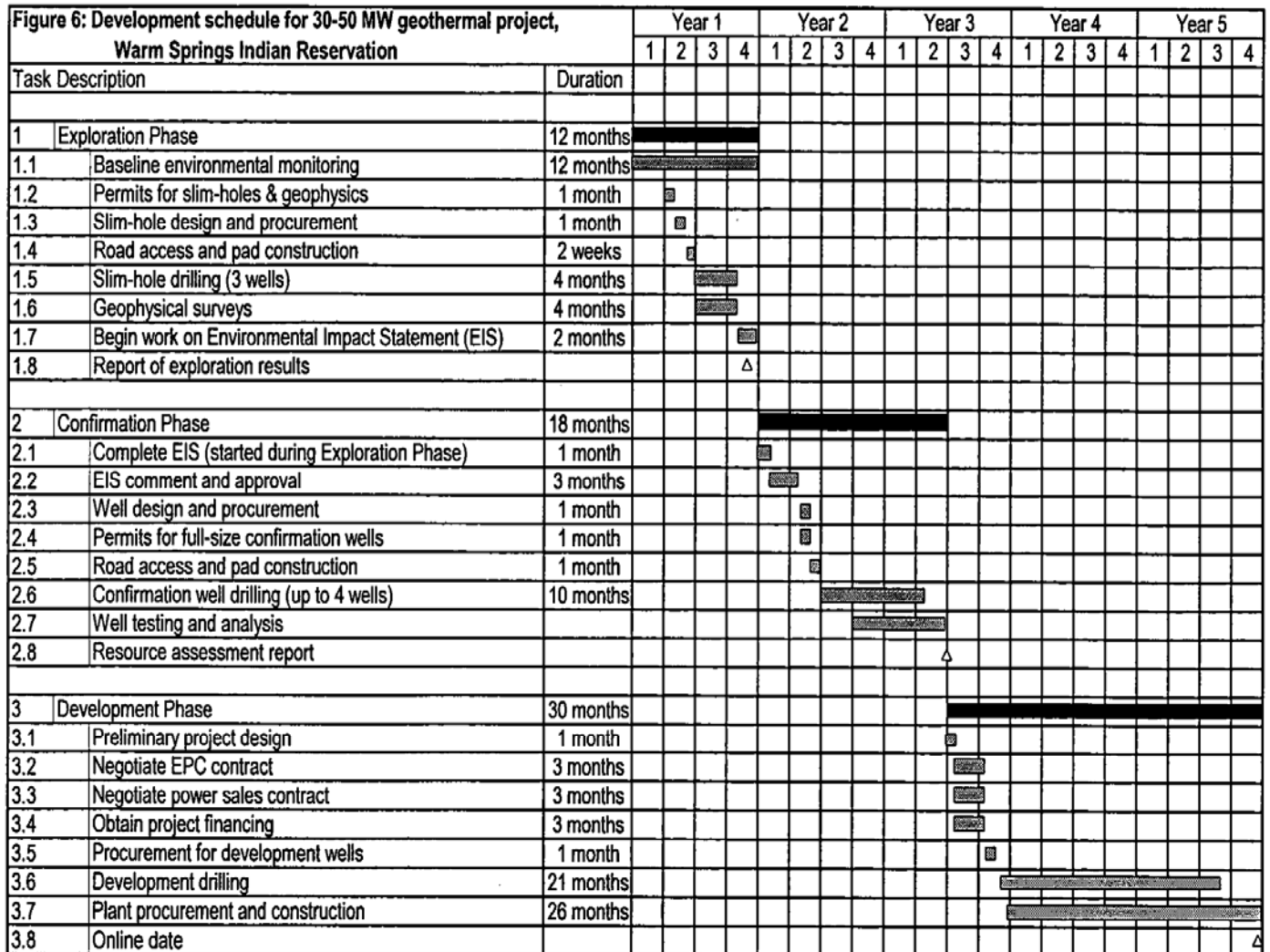


Figure 7. Modified Timeline for Schedule Delays, Tribal Review and Evaluation

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Figure 8. Diagram of a Flash Technology Geothermal Power Plant

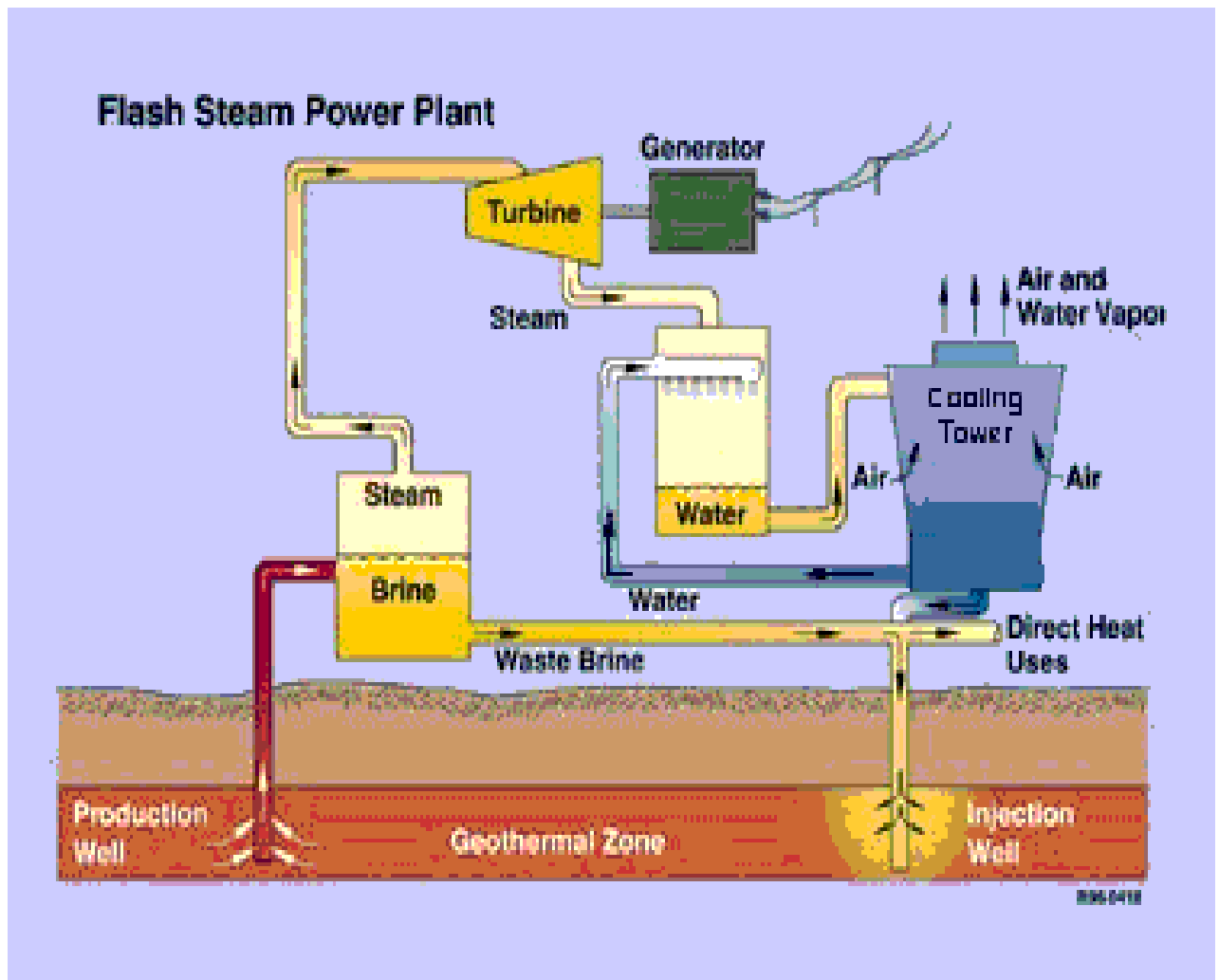


Figure 9. Diagram of a Binary Technology Geothermal Power Plant

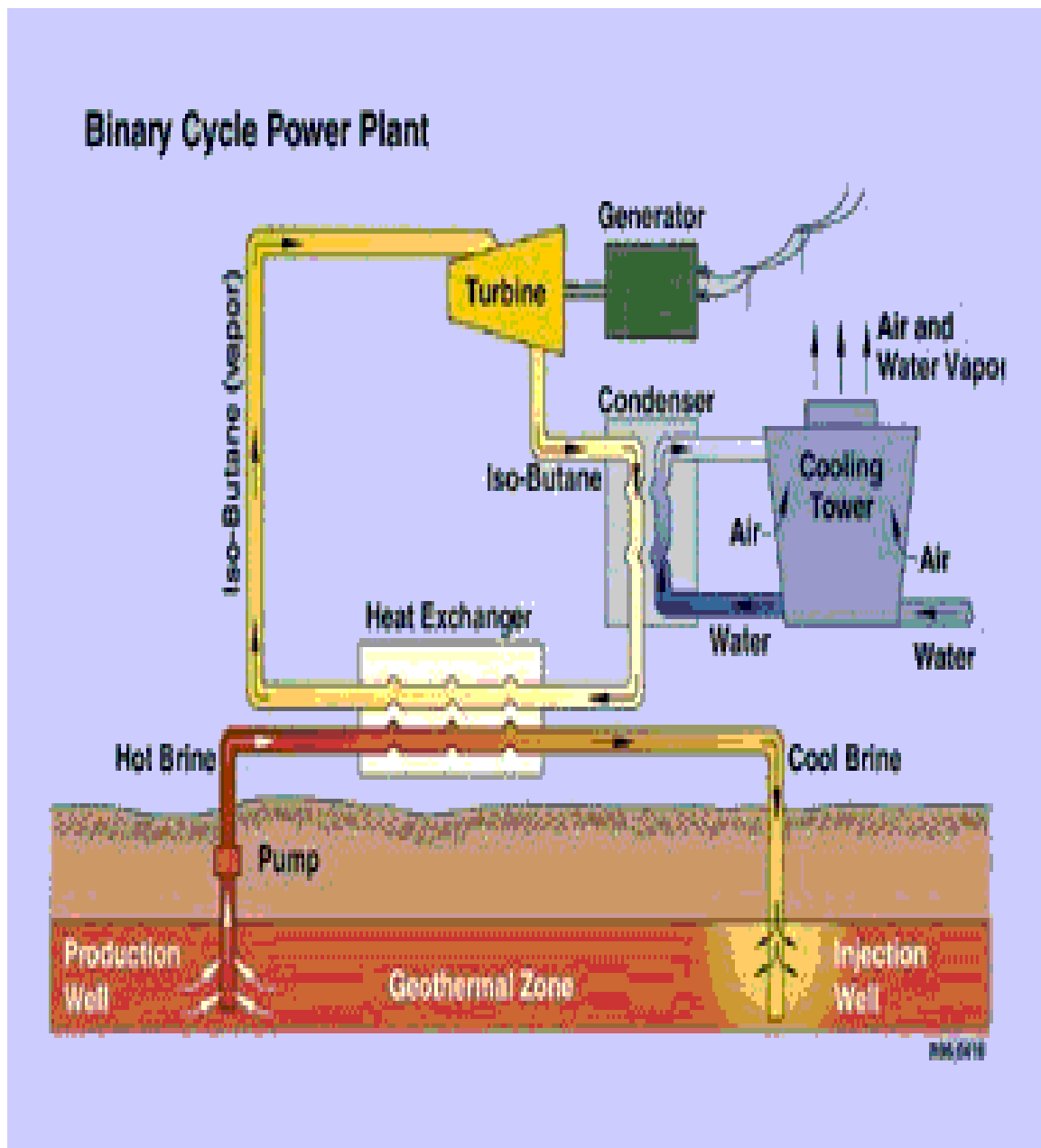
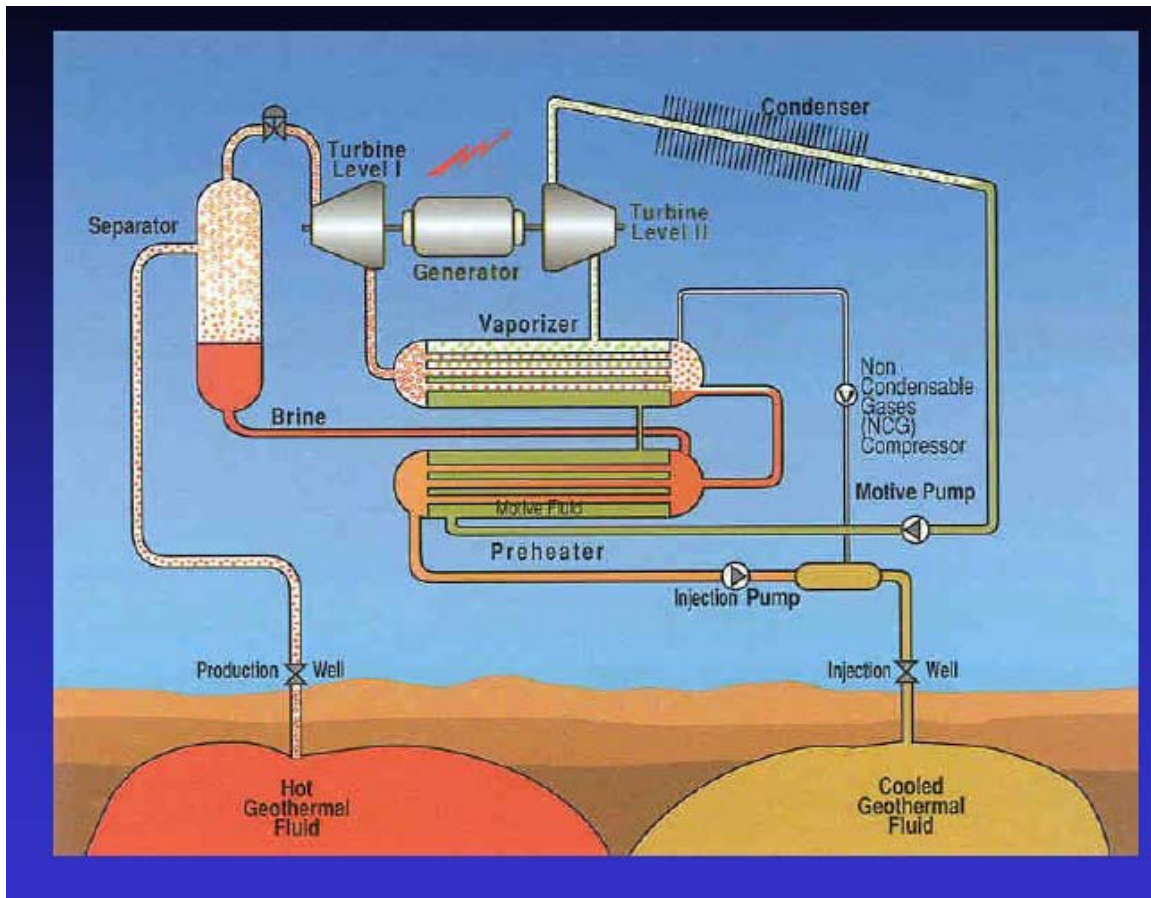


Figure 10. Diagram of a Hybrid Flash/Binary Cycle Power Plant



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Attachment

GeothermEx Report.
Submitted separately via US Mail.